National Offshore Wind Energy Grid Interconnection Study

Final Technical Report

DOE Award No. EE-0005365

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Project Period: 10/11 – 04/14

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July 30, 2014

ACKNOWLEDGMENTS

This report is based on work supported by the U.S. Department of Energy (DOE) under Award No. EE-0005365. The authors wish to express appreciation for the kind support from DOE and the many industry leaders that have contributed through direct input and comment on the work as it has progressed. In particular, we would like to thank the study's technical review committee (TRC) for their tremendous input and support for this work. Representatives from utilities, regional system operators, government, and the wind industry comprised the TRC.

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TABLE OF CONTENTS

LIST OF ACRONYMS **7**

LIST OF FIGURES **8**

LIST OF TABLES **12**

1.0 INTRODUCTION **14**

1.1 Study Background 14
1.2 Report Structure 15
1.3 Section References 16

2.0 OFFSHORE WIND DEVELOPMENT—STAGING PROJECTIONS **17**

2.1 ReEDS 17
2.2 Wind Resource Data Processing Into Supply Curves 20
2.2.1 Wind Resource Data *20*
2.2.2 Electricity Grid Data *22*
2.2.3 Supply Curve Methodology *23*
2.3 ReEDS Modeling Assumptions 24
2.4 Deployment Results 26
2.5 Factors That Influence ReEDS Deployment Decisions 29
2.6 Section References 31

3.0 WIND PRODUCTION PROFILE DEVELOPMENT **32**

3.1 Background 32
3.2 Site Selection 32
3.3 Weather Model Runs 36
3.4 Synthesis of Wind Production Profiles 37
3.5 Analysis of Ramp Frequency Distributions 43
3.6 Conclusions 47
3.7 Section References 48

4.0 INITIAL INTEGRATION ANALYSIS **49**

4.1 Introduction 49
4.2 Wind Power Profile Analysis 49
4.2.1 Summary Statistics *50*
4.2.2 Offshore Wind Power Distribution *52*
4.2.3 Hourly Offshore Wind Variability *56*
4.2.4 Ten-Minute Offshore Wind Variability *60*
4.2.5 Offshore Wind Variability and Power *63*
4.3 Load and Net Load Analysis 65
4.3.1 Summary Statistics *65*
4.3.2 Load and Net Load Distributions *66*
4.3.3 Hourly Net Load Variability *71*
4.3.4 Dependency of Load and Offshore Wind Variability *76*
4.4 Effects on Regulating Reserve Requirements 77
4.5 Conclusions 81
4.6 Section References 83

5.0 TECHNOLOGY OVERVIEW **84**

5.1 General Offshore System Structure 84
5.2 Wind Turbine Generator Types 85
5.3 Collection and Delivery 86

5.3.1 Parallel Collection Network 88
5.3.2 Series Collection Network 91
5.3.3 Delivery Systems 92
5.4 HVDC Converters 96
5.4.1 LCC 96
5.4.2 VSC 97
5.4.3 Observations About HVDC Converters 104
5.5 Multi-Terminal HVDC Systems 104
5.5.1 Existing MTDC Systems 104
5.5.2 MTDC Applications 105
5.5.3 Academic Research 106
5.6 Cables 108
5.6.1 Single-Core and Multi-Core Cables 108
5.6.2 Cable Structure 109
5.6.3 Land and Submarine Cables 112
5.6.4 Distance Limitations of AC Cables 113
5.6.5 Considerations for Cost Reduction 115
5.7 Marine Substations and Platforms 116
5.7.1 Substations 116
5.7.2 Platforms 116
5.8 Section References 119
6.0 TECHNOLOGY ASSESSMENTS 123
6.1 Costs and Trends 123
6.1.1 Cost-Reduction Efforts in the United Kingdom 123
6.1.2 Cost Reduction in the United States—Advanced Technology Demonstration Projects 125
6.1.3 Capital Cost Estimates 125
6.1.4 Cost Estimates for Various Offshore System Components 127
6.2 Reliability Assessments 131
6.2.1 Reliability of Delivery Systems 132
6.2.2 Basic HVAC and HVDC Connections 133
6.2.3 Offshore Delivery Systems 135
6.2.4 Reliability of Collection Systems 138
6.2.5 Feeder Collection Systems 139
6.2.6 Cluster Collection Systems 142
6.2.7 Reliability Assessment Conclusions 145
6.3 Preliminary Topology Comparisons 145
6.3.1 Study Model Development and Assumptions 146
6.3.2 Offshore Wind Delivery System Performance and Onshore System Impact 152
6.3.3 Preliminary Topological Comparison Conclusions 154
6.4 Regional Topology Comparisons 155
6.4.1 ERCOT 157
6.4.2 ISO-NE 158
6.4.3 MISO 160
6.4.4 The Carolinas 160
6.4.5 PJM 164
6.4.6 Conclusions 167
6.5 Production Cost Impact Assessment 168
6.5.1 Production Cost Model and Assumptions 168

6.5.2 *Base Results* ... *173*
6.5.3 *High Gas Price Sensitivity* ... *176*
6.5.4 *Low Gas Price Sensitivity* ... *179*
6.5.5 *Lower Penetration of Offshore Wind Sensitivity* ... *180*
6.5.6 *Production Cost Conclusions* ... *181*
6.6 Section References ... 182
7.0 REGULATORY REVIEW ... 184
7.1 The State of Offshore Wind in United States in 2014 ... 185
7.2 Offshore Wind Opportunities and Barriers ... 185
7.2.1 *Opportunities for Offshore Wind* ... *185*
7.2.2 *Offshore Wind Barriers* ... *187*
7.3 Regulatory Overview of Offshore Wind Permitting ... 188
7.3.1 *Site Control* ... *188*
7.3.2 *Environmental Permitting* ... *193*
7.3.3 *Power Contract* ... *195*
7.3.4 *Interconnection* ... *197*
7.3.5 *Transmission Projects* ... *199*
7.3.6 *Transmission Planning to Support Offshore Wind* ... *200*
7.4 Commercialization of Offshore Wind ... 202
7.5 Policy Recommendations ... 206
7.6 Section References ... 207
8.0 CONCLUSIONS ... 210
8.1 Key Results and Observations ... 210
APPENDIX A—TABLE OF SELECTED SITES FROM WIND PRODUCTION PROFILE DEVELOPMENT ... 212
APPENDIX B—ADDITIONAL LOAD AND NET LOAD GRAPHS ... 218
B.1 Boxplots Showing Daily Load and Net Load Variability ... 218
B.2 Contour Plots Showing Load and Net Load Power ... 222
B.3 Contour Plots Showing Load and Net Load Variability ... 223
APPENDIX C—REGIONAL TOPOLOGY COMPARISON RESULT SUMMARIES ... 225
C.1 ERCOT ... 225
C.2 ISO-NE ... 226
C.3 MISO ... 228
C.4 CAROLINAS ... 230
C.5 PJM ... 235
APPENDIX D—PRODUCTION COST ANALYSIS SITE SUMMARY ... 242

List of Acronyms

AAM - alternative arm modular
AC - alternating current
AWC - Atlantic Wind Connection
BA - balancing areas
BOEM - Bureau of Ocean Energy Management
CF - capacity factor
COE - cost of energy
COWICS - Carolina Offshore Wind Integration Case Study
CREZ - competitive renewable energy zone
CSP - concentrating solar power
CTL - cascaded two-level
DC - direct current
DFIG - doubly-fed induction generator
DOE - U.S. Department of Energy
DOI - U.S. Department of the Interior
DOWNVInD - Distant Offshore Wind farms with No Visual Impact in Deepwaters
EA - environmental assessment
EENS - expected energy not supplied
EIA - U.S. Energy Information Administration
EIS - environmental impact statement
EMM - U.S. Energy Information Agency Electricity Market Modules
ENTSO-E - European Network of Transmission System Operators for Electricity
EPR - ethylene propylene rubber
ERCOT - Electric Reliability Council of Texas
ERGIS - Eastern Renewable Generation Integration Study
EWITS - Eastern Wind Integration and Transmission Study
FERC - Federal Energy Regulatory Commission
GIP - generator interconnection process
GW - gigawatts
HV - high voltage
HVAC/HVDC - high-voltage alternating/direct current
IEC - International Electrotechnical Commission
IEEE - Institute of Electrical and Electronic Engineers
IGBT - insulated-gate bipolar transistor
ISO - independent system operator
ISO-NE - Independent System Operator New England
kV - kilovolts
kW - kilowatts
LCC - line-commutated converter
LCOE - levelized cost of energy
LMP - locational marginal prices
MASS - Mesoscale Atmospheric Simulation System
MISO - Midcontinent Independent System Operator
MMC - modular multi-level
MMS - Minerals Management Service
MOU - memorandum of understanding
MTDC - multi-terminal direct current
MVDC - medium-voltage direct current
MW - megawatts
MWh - megawatt-hours
NAMTGM - North American transmission grid model
NCF - net capacity factor
NEPA - National Environmental Policy Act
NREL - National Renewable Energy Laboratory
NERC - North American Reliability Corporation
NOWEGIS - National Offshore Wind Energy Grid Interconnection Study
NOAA - National Oceanic and Atmospheric Administration
nmi - nautical mile
NPC - neutral-point-clamped
NWPP - Northwest Power Pool
OCS - Outer Continental Shelf
ODIS - National Grid's Offshore Development Information Statement
OREC - offshore wind renewable energy certificate
PCC - point of common coupling
PJM - the regional transmission organization covering all or parts of 13 states and the District of Columbia
PPA - power purchase agreement
PUC - public utilities commission
REC - renewable energy certificate
ReEDS - Regional Energy Deployment System
RPS - renewable portfolio standards
RTO - regional transmission organization
TRC - technical review committee
TWh - terawatt-hours
USGS - U.S. Geological Survey
var - volt-ampere reactive
VOWTAP - Virginia Offshore Wind Technology Advancement Program
VSC - voltage source converter
WEA - wind energy area
WTG - wind turbine generator
XLPE - cross-linked polyethylene

LIST OF FIGURES

FIGURE 1-1. NOWEGIS TASKS AND STUDY FLOW 15
FIGURE 2-1. REEDS REGIONS SHOWING THE DIFFERENT AGGREGATION LEVELS 18
FIGURE 2-2. DISCRETIZATION OF THE LOAD DURATION CURVE UTILIZING THE 17 TIME SLICES DEFINED IN REEDS 19
FIGURE 2-3. WIND RESOURCE EXCLUSIONS 22
FIGURE 2-4. DEVELOPABLE SITE TO GRID-ASSIGNMENT PROCESS 24
FIGURE 2-5. ONSHORE AND OFFSHORE WIND INSTALLED IN 20% WIND ENERGY BY 2030 25
FIGURE 2-6. INSTALLED OFFSHORE WIND BY YEAR 25
FIGURE 2-7. CUMULATIVE INSTALLED CAPACITY BY YEAR 26
FIGURE 2-8. GENERATION BY TYPE 27
FIGURE 2-9. ONSHORE AND OFFSHORE WIND DEPLOYED IN 2030 28
FIGURE 2-10. INSTALLED WIND CAPACITY BY STATE 28
FIGURE 2-11. OFFSHORE WIND BUILD-OUT FOR THE EAST COAST 29
FIGURE 3-1. EWITS OFFSHORE SITES 32
FIGURE 3-2. NATIONAL OFFSHORE WIND NCF MAP 34
FIGURE 3-3. MAP OF 209 SELECTED POTENTIAL OFFSHORE WIND PROJECTS (RED CIRCLES) ALONG WITH REEDS ZONES WITH (YELLOW) AND WITHOUT (BLUE) CAPACITY TARGETS 36
FIGURE 3-4. MESOSCALE MODEL GRID CONFIGURATION. BLUE RECTANGLES DENOTE 2-KM EWITS GRIDS, RED ARE 2-KM NOWEGIS GRIDS, AND GREEN ARE 8-KM NOWEGIS GRIDS 37
FIGURE 3-5. STATIONS USED IN THE MODEL ADJUSTMENT AND VALIDATION 39
FIGURE 3-6. MODELED (RED) AND MEASURED (BLUE) ANNUAL, MONTHLY, AND DIURNAL MEAN WIND SPEEDS AS WELL AS THE FREQUENCY DISTRIBUTION OF HOURLY WIND SPEED CHANGES AT CHESAPEAKE LIGHT, VIRGINIA. 40
FIGURE 3-7. AS IN FIGURE 3-6, BUT FOR SOUTHWEST PASS, LOUISIANA. 41
FIGURE 3-8. AS IN FIGURE 3-6, BUT FOR ROCK OF AGES, MINNESOTA. 41
FIGURE 3-9. STANDARD DEVIATION OF DIURNAL MEAN 10-MINUTE RAMPS IN NET POWER (MW) AT A SAMPLE SITE 42
FIGURE 3-10. DIURNAL DATA CORRECTION DEVELOPED FOR NOWEGIS. MEAN DIURNAL NET POWER BEFORE AND AFTER THE CORRECTION ARE SHOWN IN BLUE AND GREEN, RESPECTIVELY. THE DIURNAL MEAN STANDARD DEVIATIONS OF 10-MINUTE CHANGES IN NET POWER BEFORE AND AFTER THE CORRECTION ARE SHOWN IN RED AND PURPLE, RESPECTIVELY. 42
FIGURE 3-11. DIURNAL MEAN STANDARD DEVIATION OF 10-MINUTE NET POWER CHANGES FROM 15 SITES OFFSHORE CALIFORNIA BEFORE (BLUE) AND AFTER (RED) THE AGGREGATE DIURNAL CORRECTION 43
FIGURE 3-12. COMPARISON OF ONSHORE (BLACK) AND OFFSHORE (RED) NET POWER FOR A SINGLE SITE IN MICHIGAN NORMALIZED BY NAMEPLATE CAPACITY. MEAN MONTHLY AND DIURNAL PATTERNS ARE SHOWN IN THE LEFT PANELS; WHEREAS 10-MINUTE AND 60-MINUTE RAMPS IN NET POWER ARE SHOWN IN THE RIGHT PANELS. 44
FIGURE 3-13. AS IN FIGURE 3-12, BUT FOR A SINGLE SITE IN NORTH CAROLINA 45
FIGURE 3-14. AS IN FIGURE 3-12, BUT FOR AN AGGREGATE OF SITES IN MICHIGAN 46
FIGURE 3-15. AS IN FIGURE 3-14, BUT FOR AN AGGREGATE OF SITES IN RHODE ISLAND 47
FIGURE 4-1. AVERAGE CFS BY REGION AND YEAR 51
FIGURE 4-2. BOXPLOTS SHOWING NORMALIZED WIND POWER BY REGION AND YEAR 52
FIGURE 4-3. BOXPLOTS SHOWING NORMALIZED POWER BY MONTH AND REGION FOR 2006 AND THE THREE YEARS COMBINED 53
FIGURE 4-4. BOXPLOTS SHOWING NORMALIZED WIND POWER BY HOUR OF DAY AND REGION FOR SELECTED MONTHS IN 2006 54
FIGURE 4-5. AVERAGE NORMALIZED WIND POWER BY HOUR OF DAY AND REGION FOR ALL THREE YEARS 55
FIGURE 4-6. CONTOUR PLOTS SHOWING AVERAGE WIND POWER BY MONTH AND HOUR OF DAY 56
FIGURE 4-7. BOXPLOTS SHOWING HOURLY RAMPS BY REGION AND YEAR 56
FIGURE 4-8. NORMALIZED HOURLY RAMP DISTRIBUTIONS FOR ALL THREE YEARS 57
FIGURE 4-9. NORMALIZED HOURLY RAMP DISTRIBUTIONS BY REGION FOR 2006 57
FIGURE 4-10. NORMALIZED HOURLY RAMP DURATION CURVES FOR 2006 58
FIGURE 4-11. NORMALIZED HOURLY RAMP DISTRIBUTIONS FOR SELECTED MONTHS IN 2006 58
FIGURE 4-12. BOXPLOTS SHOWING NORMALIZED HOURLY RAMPS BY REGION AND HOUR OF DAY FOR SELECTED MONTHS IN 2006 59
FIGURE 4-13. CONTOUR PLOTS SHOWING AVERAGE HOURLY RAMPS BY MONTH AND HOUR OF DAY 60

Figure 4-14. Boxplots showing 10-minute ramps by region and year 60
Figure 4-15. Normalized ramp distributions for all three years 61
Figure 4-16. Normalized 10-minute ramp distributions by region for 2006 61
Figure 4-17. Normalized 10-minute ramp duration curves for 2006 62
Figure 4-18. Normalized 10-minute ramp distributions for selected months in 2006 62
Figure 4-19. Boxplots showing normalized wind ramps by hour of day and region for selected months in 2006...63
Figure 4-20. Hourly normalized ramps versus normalized power 64
Figure 4-21. Ten-minute normalized ramps versus normalized power 64
Figure 4-22. Load and net load power duration curves 67
Figure 4-23. Load and net load power duration curves normalized to the peak value 67
Figure 4-24. Average monthly load and net load by region 68
Figure 4-25. Average daily load and net load profiles by region 68
Figure 4-26. Average load and net load shapes for selected months 69
Figure 4-27. Average load and net load shapes for selected months normalized to the month average peak value 70
Figure 4-28. Contour plots showing average load and net load by month and hour of day for New England.......71
Figure 4-29. Contour plots showing average load and net load by month and hour of day for the Carolinas......71
Figure 4-30. Contour plots showing average load and net load by month and hour of day for Northern California 71
Figure 4-31. Hourly load and net load ramp duration curves 72
Figure 4-32. Boxplots showing load and net load hourly variability by hour of day 73
Figure 4-33. Boxplots comparing load and net load hourly variability by hour of day 74
Figure 4-34. Boxplots comparing load and net load hourly variability for selected months by hour of day.........75
Figure 4-35. Contour plots showing average load and net load ramps by month and hour of day for New England 76
Figure 4-36. Contour plots showing average load and net load ramps by month and hour of day for the Carolinas 76
Figure 4-37. Contour plots showing average load and net load by month and hour of day for Northern California 76
Figure 4-38. Offshore wind ramps versus load ramps by region for selected months 77
Figure 4-39. Offshore wind forecast errors with 95% confidence intervals 79
Figure 4-40. Offshore wind forecast errors with 95% confidence intervals for all regions 79
Figure 4-41. Sample load, wind power, and reserve time series for PJM 80
Figure 4-42. Sample load, wind power, and reserve time series for the Carolinas 80
Figure 4-43. Reserve components and total requirements by region 81
Figure 5-1. Generalized concept for an offshore wind energy system 84
Figure 5-2. Current wind turbine types and their general configurations 85
Figure 5-3. Conventional AC offshore wind collection and delivery system 86
Figure 5-4. Conventional AC offshore wind collection with DC delivery system 87
Figure 5-5. Possible components for the collector system electrical equipment train 87
Figure 5-6. Example WTG topology options 88
Figure 5-7. Parallel collection network 88
Figure 5-8. Offshore wind farm collection system with radial configuration 89
Figure 5-9 Offshore wind farm collection system with single-sided ring configuration 90
Figure 5-10 Offshore wind farm collection system with double-sided ring configuration 90
Figure 5-11 Offshore wind farm collection system with star configuration 91
Figure 5-12 Series DC collection network 91
Figure 5-13 Series DC collection network with offshore platform 91
Figure 5-14 Series DC collection network without offshore platform 91

Figure 5-15 AC parallel connection network with star configuration 92
Figure 5-16. Offshore wind farm delivery system with radial connection 94
Figure 5-17. Offshore wind farm delivery system with split connection 94
Figure 5-18. Offshore wind farm delivery system with backbone connection 94
Figure 5-19. Offshore wind farm delivery system with offshore grid 95
Figure 5-20. (a) Six-pulse thyristor circuit, (b) Twelve-pulse thyristor circuit 96
Figure 5-21. (a) Idealized voltage across DC terminals of a six-pulse bridge and (b) idealized voltage across DC terminals of a twelve-pulse bridge 97
Figure 5-22. Two-level single-phase VSC circuit configuration and output waveform 97
Figure 5-23. Three-phase, two-level VSC 98
Figure 5-24. One leg of a three-level neutral-point clamped (NPC) converter 98
Figure 5-25. Three-phase, three-level NPC circuit diagram 99
Figure 5-26. Voltage output of two-level (left) and three-level (right) NPC converters; line-to-neutral voltages (top); and line-to-line voltages (bottom) 99
Figure 5-27. MMC approach 100
Figure 5-28. Different switching states and their corresponding current flow 100
Figure 5-29. Single-line diagram of a CTL-based converter 102
Figure 5-30. Valve arms with cascaded two-level cells (upper left). The right shows the three-dimensional model of the mechanical design. The lower left graph shows the AC voltage characteristics. 102
Figure 5-31. Sum of the cell voltages for positive (solid) and negative (dashed) as well as two times the mean direct voltage (which is noisy because of the switching harmonics). Courtesy of ABB. 102
Figure 5-32. A series hybrid circuit, also known as an AAM converter 103
Figure 5-33. Output waveform of an AAM converter 103
Figure 5-34. Existing MTDC lines 105
Figure 5-35. Locations with strong potential in renewable generation (Illustration by ABB) 105
Figure 5-36. Conceptual MTDC configuration for the integration of offshore wind power 107
Figure 5-37. MTDC configuration using series current-source inverters 107
Figure 5-38. Single-core and three-core XLPE armored cables (Illustrations from ABB) 108
Figure 5-39. Example of single core HVDC submarine cable (Illustrations from ABB Inc.) 109
Figure 5-40. Maximum real power transfer in 138-kV, 230-kV, and 345-kV 2,000-kcmil, single-core, copper cables (wide spacing) with onshore/offshore reactive compensation splits of 100/0 and 50/50 114
Figure 5-41. Maximum real power transfer in 138-kV, 230-kV, and 345-kV 2,000 kcmil, three-core, copper cables with onshore/offshore reactive compensation splits of 100/0 and 50/50 114
Figure 5-42. Conventional jacket and topside platform 117
Figure 5-43. Example jack-up platform 117
Figure 5-44. Example GBS platform 118
Figure 5-45. Installation of gravity-based structure 119
Figure 6-1. Installed capital costs for 2010 reference offshore wind 126
Figure 6-2. Conventional offshore wind collection and delivery systems 132
Figure 6-3. Double-circuit HVAC connection 133
Figure 6-4. Bipolar HVDC connections 134
Figure 6-5. Wind farm production duration curve 135
Figure 6-6. Offshore wind farm delivery system with split HVAC connection 135
Figure 6-7. Offshore wind farm delivery system with separate HVDC links 136
Figure 6-8. Three-terminal HVDC offshore wind farm delivery system 136
Figure 6-9. Offshore wind backbone delivery system 137
Figure 6-10. Offshore wind grid delivery system 138
Figure 6-11. Layout of the example wind farm 139
Figure 6-12. Typical topologies of feeder collection systems 140
Figure 6-13. Switchgear arrangements for MVAC collection systems 141

Figure 6-14. Feeder wind turbine collection system 143
Figure 6-15. Cluster wind turbine collection systems 143
Figure 6-16. Onshore interconnection substations 146
Figure 6-17. Offshore wind delivery system—radial connection with evenly spread wind generation 148
Figure 6-18. Offshore wind delivery system—backbone connection 149
Figure 6-19. Hudson onshore HVDC converter station 150
Figure 6-20. Hudson onshore HVDC converter station 151
Figure 6-21. Offshore wind delivery system—grid connection 152
Figure 6-22. Map of wind site locations 155
Figure 6-23. Map of wind site locations and onshore interconnections—ERCOT 157
Figure 6-24. Map of wind site locations and onshore interconnections—ISO-NE 158
Figure 6-25. Map of wind site locations and onshore interconnections—MISO 160
Figure 6-26. Map of wind site locations and onshore interconnections—Carolinas 162
Figure 6-27. Map of wind site locations and onshore interconnections—NOWEGIS compared to COWICS 163
Figure 6-28. Map of wind site locations and onshore interconnections—PJM 164
Figure 6-29. Map of offshore wind site interconnections to the offshore backbone system—PJM 166
Figure 6-30. Transmission grids of North America 169
Figure 6-31. Wind generation duration curves by offshore regions 170
Figure 6-32. EIA Electricity Market Module (EMM) regions 171
Figure 6-33. LMP contour map without offshore wind power 175
Figure 6-34. LMP contour map with 54 GW offshore wind power 175
Figure 6-35. LMP contour map without offshore wind power (20% higher gas prices) 178
Figure 6-36. LMP contour map with 54 GW of offshore wind power (20% higher gas prices) 178
Figure 7-1 Smart from the Start 190
Figure 7-2. BOEM regulatory process 191
Figure 7-3. MOU signed to promote offshore wind on OCS 195
Figure 7-4. RTOs 199
Figure B-1. Boxplots showing load and net load hourly variability by hour of day for January 2006 218
Figure B-2. Boxplots showing load and net load hourly variability by hour of day for April 2006 219
Figure B-3. Boxplots showing load and net load hourly variability by hour of day for July 2006 220
Figure B-4. Boxplots showing load and net load hourly variability by hour of day for October 2006 221
Figure B-5. Contour plots showing average load and net load by month and hour of day for PJM 222
Figure B-6. Contour plots showing average load and net load by month and hour of day for MISO 222
Figure B-7. Contour plots showing average load and net load by month and hour of day for NWPP 222
Figure B-8. Contour plots showing average load and net load by month and hour of day for ERCOT 223
Figure B-9. Contour plots showing average load and net load ramp by month and hour of day for PJM 223
Figure B-10. Contour plots showing average load and net load ramp by month and hour of day for MISO 223
Figure B-11. Contour plots showing average load and net load ramp by month and hour of day for NWPP 224
Figure B-12. Contour plots showing average load and net load ramp by month and hour of day for ERCOT 224

LIST OF TABLES

TABLE 2-1. GENERATION, STORAGE, AND DEMAND 18
TABLE 2-2. WIND CAPACITY FACTOR GROUP DEFINITION 21
TABLE 2-3. EXCLUSIONS AND CONSTRAINTS OF ONSHORE WIND POWER 21
TABLE 2-4. PARAMETERS THAT INFLUENCE DEPLOYMENT DECISIONS FOR AREAS WITH AND WITHOUT WIND INSTALLED IN 2030 31
TABLE 3-1. EXCLUSIONS AND CONSTRAINTS OF OFFSHORE WIND POWER 33
TABLE 3-2. SUMMARY OF SELECTED SITES BY REGION....36
TABLE 3-3. MESOSCALE MODEL CONFIGURATION 37
TABLE 3-4. STATIONS USED IN THE MODEL ADJUSTMENT AND VALIDATION 39
TABLE 4-1. INSTALLED OFFSHORE CAPACITY BY GRIDVIEW REGION....49
TABLE 4-2. SUMMARY STATISTICS FOR WIND POWER DISTRIBUTIONS (MW AND %) FOR 2006....50
TABLE 4-3. SUMMARY STATISTICS FOR HOURLY RAMP DISTRIBUTIONS (MW AND %) FOR 2006....51
TABLE 4-4. SUMMARY STATISTICS FOR 10-MINUTE RAMP DISTRIBUTIONS (MW AND %) FOR 2006 52
TABLE 4-5. SUMMARY STATISTICS FOR LOAD AND NET LOAD POWER DISTRIBUTIONS (MW) 65
TABLE 4-6. SUMMARY STATISTICS FOR HOURLY LOAD AND NET LOAD RAMP DISTRIBUTIONS (MW) 66
TABLE 4-7. RELATIONSHIPS AMONG LOAD STATISTICS AND INSTALLED WIND CAPACITY....66
TABLE 4-8. LOAD AND TOTAL RESERVE REQUIREMENTS AND DIFFERENCES....81
TABLE 5-1 TYPICAL WEIGHT OF PLATFORMS (TOPSIDE) 117
TABLE 6-1. DOE OFFSHORE WIND—ADVANCED TECHNOLOGY DEMONSTRATION PROJECTS 125
TABLE 6-2. CONVERSION FACTORS FOR COSTS OF OFFSHORE WIND EQUIPMENT 127
TABLE 6-3. APPROXIMATE COST OF VARIOUS HVDC VSCS 127
TABLE 6-4. APPROXIMATE COST FOR HVDC EXTRUDED SUBSEA CABLES 128
TABLE 6-5. APPROXIMATE COST FOR VARIOUS HVAC THREE-CORE AC SUBSEA CABLES 128
TABLE 6-6. APPROXIMATE COST FOR HVDC OVERHEAD AND UNDERGROUND LINES.... 128
TABLE 6-7. APPROXIMATE COST OF TRANSFORMERS.... 129
TABLE 6-8. APPROXIMATE COST FOR HVAC GAS-INSULATED SUBSTATION SWITCHGEAR.... 129
TABLE 6-9. APPROXIMATE COST FOR HVAC SHUNT REACTORS 129
TABLE 6-10. APPROXIMATE COST FOR HVAC CAPACITOR BANKS 129
TABLE 6-11. APPROXIMATE COST FOR HVAC STATIC VAR COMPENSATORS 129
TABLE 6-12. APPROXIMATE COST FOR HVAC STATIC COMPENSATORS 130
TABLE 6-13. APPROXIMATE COST FOR VARIOUS OFFSHORE PLATFORMS 130
TABLE 6-14. APPROXIMATE CONSTRUCTION COST FOR SUBSEA OBSTACLE CROSSING OF AC AND DC CABLES 130
TABLE 6-15. APPROXIMATE CONSTRUCTION COST FOR HORIZONTAL DIRECTIONAL DRILLING AND ONSHORE CABLE INSTALLATIONS 131
TABLE 6-16. APPROXIMATE CONSTRUCTION COSTS FOR SHORELINE TRANSITIONS/LANDFALL 131
TABLE 6-17. OUTAGE STATISTICS FOR HVAC AND HVDC DELIVERY SYSTEMS 133
TABLE 6-18. AVAILABILITY OF DELIVERY CAPACITY FOR THE TWO POINT-TO-POINT CONNECTIONS 134
TABLE 6-19. RELIABILITY OF THE TWO POINT-TO-POINT CONNECTIONS.... 134
TABLE 6-20. OUTAGE STATISTICS FOR WIND TURBINE COLLECTION SYSTEMS 139
TABLE 6-21. RELIABILITY OF FEEDER WIND TURBINE COLLECTION SYSTEMS 142
TABLE 6-22. IMPACTS ON EENS BY FEEDER CABLE REPAIRING TIME.... 142
TABLE 6-23. RELIABILITY OF FEEDER WIND TURBINE COLLECTION SYSTEMS 144
TABLE 6-24. WIND GENERATION OUTPUT SCENARIOS.... 146
TABLE 6-25. POWER INJECTION AT EACH ONSHORE SUBSTATION 153
TABLE 6-26. POWER INJECTION AT EACH ONSHORE SUBSTATION—HVAC OFFSHORE DELIVERY SYSTEM.... 154
TABLE 6-27. OFFSHORE WIND SITE DELIVERY SYSTEM RECOMMENDATION—ERCOT 157
TABLE 6-28. ADDITIONAL THERMAL VIOLATIONS WITH OFFSHORE WIND—ERCOT.... 157

Table 6-29. Offshore Wind Site Delivery System Recommendations—ISO-NE ... 159
Table 6-30. Additional Thermal Violations with Offshore Wind—ISO-NE ... 159
Table 6-31. Offshore Wind Site Delivery System Recommendations—MISO ... 160
Table 6-32. Additional Thermal Violations with Offshore Wind—MISO ... 160
Table 6-33. Offshore Wind Site Delivery System Recommendations—Carolinas ... 162
Table 6-34. Additional Thermal Violations with Offshore Wind—Carolinas ... 162
Table 6-35. Additional Thermal Violation Comparisons for the 100% Case ... 163
Table 6-36. Offshore Wind Site Delivery System Recommendations—PJM ... 164
Table 6-37. Additional Reactive Support Required in Delaware Peninsula Area (with Different Wind Generation Output Level) ... 165
Table 6-38. Thermal Violations with Offshore Wind—PJM ... 165
Table 6-39. Onshore Substation Power Injection with Different Offshore Delivery Systems ... 167
Table 6-40. Additional Reactive Supports Required in Delaware Peninsula Area (Various Offshore Delivery Systems with 50% Wind Generation Output Levels) ... 167
Table 6-41. Thermal Violations with Different Offshore Wind Delivery Systems—PJM ... 167
Table 6-42. Details of the Integrated NAMTGM ... 170
Table 6-43. Fuel Prices by EMM Region in $2020, $2011, and $Nominal ... 172
Table 6-44. Regional Contingency Reserve Requirements ... 173
Table 6-45. Offshore Wind Power Dispatch Summary by Coastal Region ... 174
Table 6-46. Summary of Base Production Costs by NERC Subregion ... 174
Table 6-47. Summary of Production Costs with High Gas Prices ... 177
Table 6-48. Summary of Production Costs with Low Gas Prices ... 179
Table 6-49. Summary of Production Costs with 27 GW of Offshore Wind ... 180
Table 6-50. Summary of Production Costs with 16 GW of Offshore Wind ... 181
Table 6-51. Sensitivity of Offshore Wind Value to Penetration Levels ... 182
Table 7-1. Key Offshore Wind Barriers ... 187
Table 7-2. Jurisdictional Chart for the Regulation of Offshore Wind ... 188
Table 7-3. Proposed Commercial Offshore Wind Projects by State ... 205
Table A-1. Table of Selected Sites from Wind Production Profile Development ... 212
Table C-1. ERCOT Thermal Violations with 30% Offshore Wind Output—827 MW ... 225
Table C-2. ERCOT Thermal Violations with 50% Offshore Wind Output—1,378 MW ... 225
Table C-3. ERCOT Thermal Violations with 100% Offshore Wind Output—2,755 MW ... 225
Table C-4. ISO-NE Thermal Violations with 30% Offshore Wind Output—4,361 MW ... 226
Table C-5. ISO-NE Thermal Violations with 50% Offshore Wind Output—7,269 MW ... 226
Table C-6. ISO-NE Thermal Violations with 100% Offshore Wind Output—14,537 MW ... 226
Table C-7. MISO Thermal Violations with 30% Offshore Wind Output—724 MW ... 228
Table C-8. MISO Thermal Violations with 50% Offshore Wind Output—1,207 MW ... 228
Table C-9. MISO Thermal Violations with 100% Offshore Wind Output—2,413 MW ... 228
Table C-10. Carolinas Thermal Violations with 30% Offshore Wind Output—2,484 MW ... 230
Table C-11. Carolinas Thermal Violations with 50% Offshore Wind Output—4,140 MW ... 230
Table C-12. Carolinas Thermal Violations with 100% Offshore Wind Output—8,281 MW ... 230
Table C-13. Carolinas Thermal Violations with 100% Offshore Wind Output [Duke Upgrade]—8,281 MW ... 232
Table C-14. PJM Thermal Violations with 30% Offshore Wind Output—6,127 MW ... 235
Table C-15. PJM Thermal Violations with 50% Offshore Wind Output—10,212 MW ... 235
Table C-16. PJM Thermal Violations with 100% Offshore Wind Output—20,425 MW ... 237
Table C-17. PJM Thermal Violations with 50% Offshore Wind Output (HVDC Backbone)—10,212 MW ... 239
Table C-18. PJM Thermal Violations with 50% Offshore Wind Output (HVAC Backbone)—10,212 MW ... 240
Table D-1. Selected Offshore Wind Farms in the Atlantic Region ... 242
Table D-2. Selected Offshore Wind Farms in the Pacific, Gulf, and Great Lakes Regions ... 243

1.0 INTRODUCTION

1.1 Study Background

The United States has multiple objectives in developing a national energy strategy. Among these are increasing economic growth, improving environmental quality, and enhancing national energy security. Electric power generated by wind resources has become an increasingly important part of the nation's energy production portfolio. All current U.S. wind production is land based, despite significant accessible offshore wind resources. Many factors contribute to the lower use of offshore wind resources, but among them are accessibility to data for determining resource levels and optimal locations as well as the difficulty and cost of transmitting the wind-generated electricity to the onshore power grid.

In February 2011, the U.S. Department of Energy (DOE) published *A National Offshore Wind Strategy* [1], which identified numerous market barriers to the adoption of responsible commercial offshore wind development. As part of its national strategy, the Offshore Wind Innovation and Demonstration initiative, DOE issued funding opportunity announcement DE-FOA-0000414 to encourage studies to help address these barriers. One of these efforts is the National Offshore Wind Energy Grid Interconnection Study (NOWEGIS), a study that will help provide the data necessary to produce a roadmap to achieving offshore wind energy goals such as those proposed in the DOE report *20% Wind Energy by 2030* [2]. That report indicated the potential to achieve 54 gigawatts (GW) of deployed offshore wind-generating capacity by 2030 (at a production cost of $0.07/kWh) and 10 GW of capacity deployed by 2020 (at a production cost of $0.10/kWh). The guidance received through the entirety of the funding opportunity announcement efforts will also assist in bringing the United States levels of renewable resources more comparable to those achieved in other areas of the world, such as Europe.

The intent of the NOWEGIS effort described in this report was to help address DOE's two critical objectives in overcoming offshore wind barriers: to reduce the cost of energy (COE) and to reduce deployment timelines. The study built upon the significant body of work previously performed under DOE's direction and by the wind industry to identify various opportunities for and roadblocks to the integration of offshore wind energy into the various interconnections throughout the United States. The study team, led by ABB, Inc., included AWS Truepower, Duke Energy, the National Renewable Energy Laboratory (NREL), and the University of Pittsburgh. Each of the team members' strengths and areas of expertise were leveraged to address four primary tasks that assessed offshore wind development around the United States coastal regions, including the Atlantic Ocean, the Gulf of Mexico, the Great Lakes, and the Pacific Ocean. These areas as well as the flow of the study are illustrated in Figure 1-1, and a more detailed description of the study areas is given below.

As shown, Tasks 1 through 3 are directly related and had to be performed in order. Much of the review of the technologies could be performed in parallel with these efforts, but other aspects of the review, such as production cost impact assessments, could be performed only upon completion of Task 3.

The ultimate goal of these study efforts was to provide useful information for the wind energy industry to help establish a roadmap to achieve greater levels of offshore wind power production in the United States.

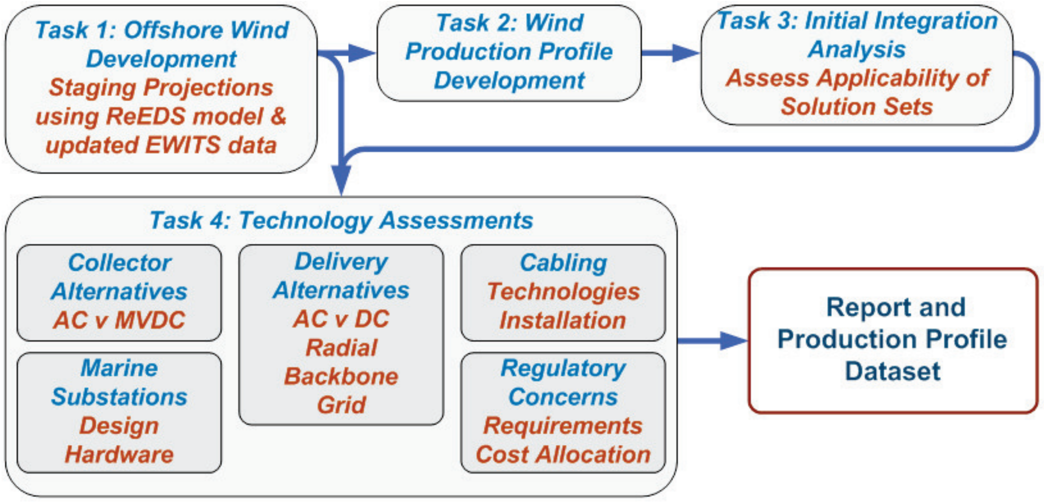

Figure 1-1. NOWEGIS tasks and study flow

The NOWEGIS study tasks were as follows:

1. **Offshore wind development staging projections**—This task determined the expected offshore wind development staging. The work built upon the Eastern Wind Integration and Transmission Study (EWITS) [3], with the data updated to reflect current trends in offshore development and expanded to include areas not previously considered. Site screening based on a geographic information system was used to select likely locations for offshore wind development, including the areas not considered in EWITS.
2. **Wind production profile development**—This task determined the wind production profiles based on the site-screening results. Mesoscale atmospheric simulations were performed to determine the anticipated wind power production profiles appropriate for integration studies.
3. **Initial integration analysis**—This task assessed the applicability of the traditional integration study methods to offshore wind. This initial analysis assessed integration impacts, such as wind variability, and the applicability of current wind integration study methods to deployment scenarios.
4. **Technology assessments**—This task assessed offshore wind energy collection and delivery technologies. This included a qualitative overview of the technologies currently used or those with a strong potential for consideration at some future period, as well as quantitative assessments of cost, reliability, potential operational impacts, and potential production cost impacts of several technology alternatives. Five focus areas were considered: the offshore collection system, the delivery system from platform to onshore substation, undersea cabling and installation, marine substation design and hardware, and regulatory issues.

To ensure that the study efforts were appropriately focused and of interest to the industry, a technical review committee (TRC) was established that included members from regional transmission system operators, industry groups, and governmental entities. The study team met with the TRC regularly throughout the study effort and kept them informed of progress and results.

1.2 Report Structure

The report for the NOWEGIS has been arranged as follows:

1. **Summary**—This is a stand-alone companion to the full, final report that provides a high-level overview focusing on the study purposes, results, conclusions, and brief descriptions of the task

efforts. The summary is likely to be of primary interest to decision makers and leaders in government and industry.

2. **Final report**—This is the main document. It contains detailed descriptions of the study work and is likely to be of primary interest to scientists and engineers who are involved with the selection and deployment of the wind energy efforts. Sections include:
   - Section 2—Offshore Wind Development: Staging Projections
   - Section 3—Wind Production Profile Development
   - Section 4—Initial Integration Analysis
   - Section 5—Technology Overview
   - Section 6—Technology Assessments
   - Section 7—Regulatory Review
   - Section 8—Conclusions

Each section is as compartmentalized as possible. Although some sections refer to the work in other sections, references are provided for each section individually and may be repeated in multiple sections.

1.3 Section References

[1] DOE. *A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States.* Washington, D.C.: 2011.

[2] DOE. *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricicy Supply*. DOE/GO-102008-2567. Washington, D.C.: Jul. 2008. Accessed January 2014: http://www.nrel.gov/docs/fy08osti/41869.pdf

[3] EnerNex. *Eastern Wind Integration and Transmission Study.* NREL/SR-5500-47078. Work performed by EnerNex, Knoxville, TN. Golden, CO: NREL, Feb. 2011. Accessed January 2014: http://www.nrel.gov/docs/fy11osti/47078.pdf.

2.0 OFFSHORE WIND DEVELOPMENT—STAGING PROJECTIONS

Recently there has been increased interest in investigating how the installation of offshore transmission grids can enhance the appeal of offshore wind energy. Offshore wind has already been deployed in Europe, but no offshore wind farms currently exist in the United States. It is believed that the design of an offshore transmission grid would accelerate the deployment of offshore wind in the United States.

The present study analyzed the process of planning and designing an offshore transmission layout that would accommodate the levels of deployment envisioned in DOE's report *20% Wind Energy by 2030* [1] and accompanying benefits. However, such a layout is highly dependent on the forecast for timing and the location of the offshore wind capacity coming online.

Thus, the first task in this study was to determine the location and timing for the development of the 54 GW of offshore wind capacity outlined in [1]. The deployment was determined using the Regional Energy Deployment System (ReEDS) model developed by NREL [1]. The deployment schedule from [1] was maintained, even though some predicted installations predate the issuance of the permits necessary to actually build these plants; however, the amount of capacity in this situation is relatively small and could be made up in subsequent years.

The remainder of this section will discuss the process. First, ReEDS is introduced, along with the treatment of the wind resource through supply curves. The assumptions are then summarized, and the results are explained. Finally, a discussion of the factors that affect the location of deployed wind is included.

2.1 ReEDS

Modeling future renewable energy scenarios requires tools that can accommodate the diversity of the various renewable energy technologies and applications, the location-dependent quality of many of these resources, and the inherent variability and uncertainty of wind and solar generation. Although no modeling tool can meet all needs simultaneously, ReEDS is the analytical backbone of many NREL studies that involve capacity expansion, such as the aforementioned DOE study [1][1], *Renewable Electricity Futures* [3], and the *SunShot Vision Study* [4].

ReEDS is a generation and transmission capacity expansion model of the electric power system of the contiguous United States. ReEDS is unique among nationwide and long-term capacity expansion models for its highly discretized regional structure and statistical treatment of the impact of variability of wind and solar resources on capacity planning and dispatch.

More specifically, ReEDS is a linear program that minimizes overall electric system costs subject to a large number of constraints. The major constraints include meeting electricity demand within specific regions, regional resource supply limitations, planning and operating reserve requirements, state and federal policy demands, and transmission constraints. To satisfy these constraints, the ReEDS optimization routine chooses from a broad portfolio of conventional generation, renewable generation, storage, and demand-side technologies (see Table 2-1), including the deployment location of these technologies. Additionally, because of its detailed regional and temporal representation, ReEDS can estimate the costs of transmission expansion and operational integration and has limited representation

[1] ReEDS was referred to as the Wind Deployment System (WindDS) model in the *20% Wind Energy by 2030* wind study.

of transmission power flow. Even though ReEDS does not explicitly examine all reliability criteria, it can be linked to other models with higher fidelity, such as GridView [5].

The capacity expansion and dispatch decision making of ReEDS considers the net present value cost of adding new generation capacity and operating it (considering transmission and operational integration) throughout an assumed financial lifetime (20 years). This cost-minimization routine was applied for each 2-year investment period from 2010 until 2050. As a cost-optimization model, ReEDS does not attempt to capture noneconomic (e.g., behavioral, social, institutional) considerations in its investment and dispatch decision-making routine. These noneconomic factors can be significant, particularly regionally, and further work is necessary to quantify their impacts.

Table 2-1. Generation, Storage, and Demand

Category	Technologies
Conventional generation	Pulverized coal
	Natural gas combined cycle[a]
	Natural gas combustion turbine
	Nuclear
	Integrated gasification combined cycle[a]
Renewable generation	Onshore wind
	Offshore wind
	CSP with and without thermal storage
	Utility-scale and distributed rooftop photovoltaic
	Dedicated and co-fired biomass
	Geothermal
	Hydropower
	Ocean
Storage	Pumped-storage hydropower
	Compressed air energy storage
	Batteries
Demand-Side technologies	Thermal energy storage in buildings
	Interruptible load
	Utility-controlled plug-in electric vehicle charging

a. Carbon capture and storage versions of these technologies are also implemented in ReEDS.

ReEDS represents the contiguous United States using 356 wind and concentrating solar power (CSP) resource regions. These 356 resource supply regions are grouped into four levels of larger regions: balancing areas (BAs), reserve-sharing groups, the North American Electric Reliability Corporation (NERC) regions [6], and interconnects. This level of geographic detail, depicted in Figure 2-1, enables the model to account for geospatial differences in resource quality, transmission needs, electrical (grid-related) boundaries, political and jurisdictional boundaries, and demographic distributions.

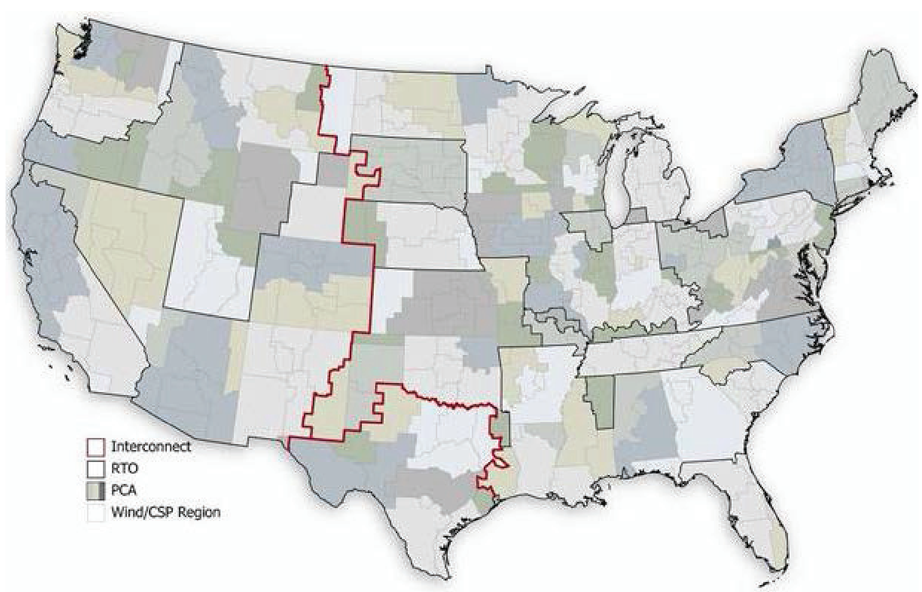

Figure 2-1. ReEDS regions showing the different aggregation levels

In ReEDS, BAs are the regional areas within which demand requirements must be satisfied. Although existing actual BA authority boundaries were considered in the design of the ReEDS BAs, the ReEDS BA boundaries are often not aligned with the boundaries of real BA authorities to accommodate other aforementioned boundaries (e.g., political boundaries).

ReEDS dispatches generation within 17 different time slices (four time slices for each season representing morning, afternoon, evening, and nighttime, with an additional summer-peak time slice). This level of temporal detail—though not as sophisticated as that of an hourly chronological dispatch model—enables ReEDS to consider seasonal and diurnal changes in demand and resource availability. Figure 2-2 compares a typical load duration curve and the discretized version based on the 17 time slices. Moreover, because significant demand and resource variations can occur within each time slice, ReEDS uses statistical calculations to estimate the capacity value, forecast error reserve, and curtailment of wind and solar resources. These calculations also consider the correlations of output profiles among projects of the same type in different locations, among projects that rely on different resource types, and among different regional demand profiles.

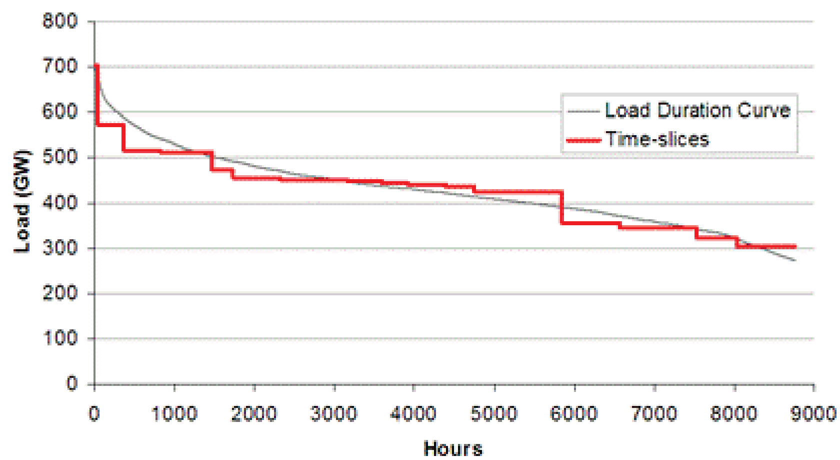

Figure 2-2. Discretization of the load duration curve utilizing the 17 time slices defined in ReEDS

The statistical calculations in ReEDS are used in multiple reserve and load-balancing constraints in the model. At the longest timescales, ReEDS enforces a planning reserve requirement that ensures there is sufficient generating capacity to exceed the annual forecasted peak demand hour by the requisite reserve margin, which ranges from 12.5% to 17.2%. At shorter hourly to sub-hourly timescales relevant to daily electric system operations, ReEDS requires sufficient supply- and demand-side technologies to satisfy operating reserve requirements. The operating reserves considered in ReEDS included wind and solar forecast error reserves, contingency reserves, and frequency regulation. Because contingency reserves and frequency regulation requirements were assumed to be established as a fraction of demand (6% for contingency and 1.5% for frequency regulation), they were independent of the amount of variable generation. In contrast, forecast error reserve requirements were estimated based on hourly persistence forecasts for wind and solar photovoltaic; therefore, they increased as variable generation increased. ReEDS does not directly capture the wear-and-tear costs associated with operating the conventional thermal power plant fleet in a more flexible fashion. Additional research on these costs and their implications for renewable energy integration are warranted.

In ReEDS, planning and operating reserves were assumed to be maintained independently in 21 reserve-sharing groups for all years of the study period, representing greater cooperation throughout larger areas than exists in the current grid. Existing regional transmission organizations (RTOs) and independent system operators (ISOs, such as Midcontinent ISO, or MISO; ISO-New England, or ISO-NE; PJM; and California ISO) were used in the construction of some of the reserve-sharing groups; when there was no existing RTO or ISO, a future reserve-sharing region was assumed. Some of these reserve-sharing groups were larger than those that currently operate with the assumption that additional market integration and transmission expansion throughout the next 40 years would expand current reserve-sharing regions.

Existing transmission infrastructure was assumed to continue to be operable throughout the study period, and existing line capacity was assumed to be usable by both conventional and renewable generation sources. The regional resolution of the ReEDS model allows it to roughly estimate new transmission expansion needs and their associated investment requirements; therefore, the ReEDS model's deployment decision-making algorithm was able to compare the total costs, including costs of additional required transmission infrastructure and of distant but higher quality renewable resources, to more local but lower quality resources based on generation and transmission cost considerations. In addition to the expansion of long-distance transmission lines, interconnection costs for new generation and storage technologies were considered in ReEDS. For wind and CSP technologies, additional interconnection supply curves were applied to account for the strong location dependence of those resources, yielding total interconnection costs for these technologies that were generally greater than those for other technologies. A detailed description of these supply curves and the transmission treatment in ReEDS is provided in the next subsection and [2]. Implicit in the ReEDS treatment of transmission is that new transmission can be built within and between regions to enable access to renewable resources and leverage geospatial, temporal, and technological diversity between resources.

These measures ensure that ReEDS results are as detailed geographically and temporally as computational constraints allow, while also being consistent with an electricity system that is able to maintain an overall balance between supply and demand. In sum, ReEDS provides a means of estimating the type and location of conventional and renewable resource development; the transmission infrastructure expansion requirements of those installations; and the composition and location of generation, storage, and demand-side technologies needed to maintain balance between supply and demand. Additional details about ReEDS can be found in [1].

2.2 Wind Resource Data Processing Into Supply Curves

This section describes the methodology used to characterize the wind resource in ReEDS. The goal is to create a supply curve that characterizes issues that cannot be explicitly represented in ReEDS, such as the transmission costs from a potential site to the interconnection point, difficulty of deploying wind in highly populated or sloped areas, and wind's interaction with potential exclusions. These issues are overlaid on top of potential resource data. An algorithm is utilized to progressively simulate the connection of wind sites to the electrical network. This treatment is applied to create wind supply curves that are utilized as an input to ReEDS for each of the 356 resource regions shown in Figure 2-1.

2.2.1 WIND RESOURCE DATA

The geospatial wind resource data was characterized as annual average gross capacity factor for a International Electrotechnical Commission (IEC) Class II wind turbine for each 200 m x 200 m across the conterminous United States. This data was produced by AWS Truepower in 2011, and it is licensed by NREL for internal use in their modeling, analysis, and mapping activities. The geospatial wind data for onshore wind was combined with the exclusion data to create an available wind resource layer with a minimum wind resource intensity of 30% gross capacity factor. This data was classified into five wind capacity factor groups each for onshore wind, offshore wind in shallow (a depth of less than 30 m) areas, and offshore wind in deep (a depth of 30 m and more) areas, as shown in Table 2-2.

Table 2-2. Wind Capacity Factor Group Definition

Location	Group 1	Group 2	Group 3	Group 4	Group 5
Onshore	30–36	36–42	42–48	48–54	> 54
Offshore shallow	30–36	36–42	42–48	48–54	> 54
Offshore deep	30–40	40–50	50–55	55–60	> 60

The wind resource data was filtered to exclude areas considered unlikely to be developed for environmental or technical reasons. These areas include national parks, wilderness areas, wildlife refuges, urban areas, airports, and areas with low wind resource (below 30% gross capacity factor). The full list of exclusions is presented in Table 2-3 [7] and Figure 2-3. The available wind by wind capacity factor group was then aggregated from the 200-m resource resolution to a 3-km x 3-km aggregate size to reduce computer processing time.

In addition to these exclusions, cost penalties were applied by the ReEDS model based on local population density and slope. The population cost multiplier varied from 1.0 to 2.0 based on population density, although the most dense areas that would have resulted in a value of 2.0 were excluded. The slope cost multiplier ranged from 1.0 to 1.0625.

Table 2-3. Exclusions and Constraints of Onshore Wind Power

Slope exclusion	> 20%	
Distance exclusion	< 3-km distance to excluded area (does not apply to water)	
Land type(s) exclusion	50% U.S. Forest Service lands (including national grasslands, excluding ridge crests)	USGS (2005)
	50% U.S. Department of Defense lands (excluding ridge crests)	USGS (2005)
	50% GAP Land Stewardship Class 2—forest	CBI (2004)
	50% Exclusion of non-ridge crest forest (noncumulative over U.S. Forest Service land)	USGS (2005)
	Airports	ESRI (2003)
	Urban areas	ESRI (2004)
	LULC—wetlands	USGS (1993)
	LULC—water	USGS (1993)
	U.S. Forest Service inventoried roadless areas	USFS (2003)
	U.S. National Park Service lands	USGS (2005)
	U.S. Fish and Wildlife Service lands	USGS (2005)
	Federal parks	USGS (2005)
	Federal wilderness	USGS (2005)
	Federal wilderness study area	USGS (2005)
	Federal national monument	USGS (2005)
	Federal national battlefield	USGS (2005)
	Federal recreation area	USGS (2005)
	Federal national conservation area	USGS (2005)
	Federal wildlife refuge	USGS (2005)
	Federal wildlife area	USGS (2005)
	Federal wild and scenic area	USGS (2005)
	GAP Land Stewardship Class 2—state and private lands equivalent to federal exclusions	CBI (2004)

Data Sources: USGS (2005) = U.S. Geological Survey federal lands data
CBI (2004) = Conservation Biology Institute Protected Areas Database
ESRI = base data provided with ESRI ArcGIS software

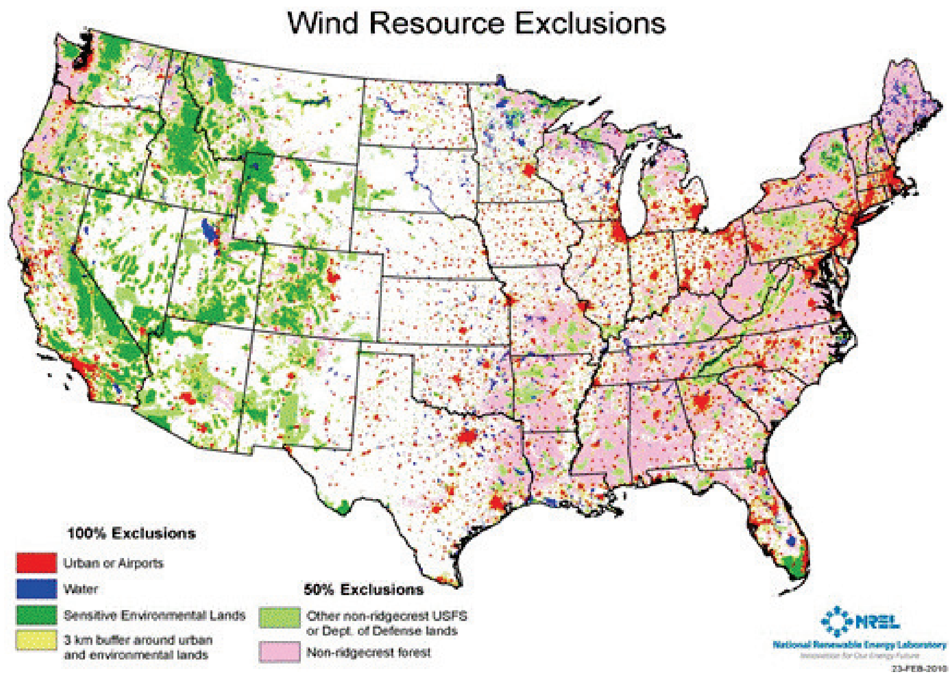

Figure 2-3. Wind resource exclusions

2.2.2 ELECTRICITY GRID DATA

The supply curves utilized four types of grid-tie features: transmission lines, substations, large load centers (cities), and regional balancing area centroids (as defined for ReEDS in Figure 2-1). Different types of grid features have different associated costs. For each grid feature, a capacity was estimated and used in the supply curve allocation process:

- Transmission line capacity was estimated based on its length and nominal voltage [8].
- Substations were linked to the transmission lines, marking their endpoints, and had a total capacity equal to the cumulative value of half of each connected transmission line's[2] capacity. When developable sites were assigned to a transmission line or substation, their linked-component capacities were reduced accordingly.
- Load centers are cities with at least 10,000 people, with the remaining population represented by county at its spatial center. The city's capacity is represented using annual peak load[3] apportioned to each city by population.
- BA connection points represent locations where large transmission lines are built from the center of one BA region to another within the ReEDS model. The inter-regional transmission capacity was considered to be unlimited.

[2] Transmission line data was extracted from the Platts POWERmap (2009) product for the contiguous United States.

[3] Regional peak load data was extracted from the Platts POWERmap and POWERdat products for the contiguous United States.

2.2.3 SUPPLY CURVE METHODOLOGY

All resource points need be assigned to a grid component to simulate the connection of wind farms to the electricity grid. First, potential wind sites were tied to available transmission, substation, and load centers. When the capacity associated with those features was exhausted, the resource points were assigned to the closest BA center.

The resource supply curves are the result of iteratively evaluating the lowest cost developable sites and allocating them to grid components based on that component's remaining available capacity. Cost is evaluated based on resource intensity, nearby population and slope impacts on cost, regional cost multipliers, and the distance to reach a grid feature. The supply curve analysis allows for the evaluation of cost trade-offs between higher intensity resources located farther from the grid and lower intensity resources that may be nearer to a grid feature.

The process begins by identifying all of the potential grid features to which a wind resource site could tie (up to the point where it reaches a BA center), and calculating the cost for each of those potential connections. These links are sorted by cost, and the lowest cost site is selected. Each grid component to which the site could potentially be tied is identified, and its remaining available capacity is queried. If the grid component capacity can accept the site capacity, the site is classified as assigned (meaning its remaining potential links will no longer be considered), and the grid component's available capacity is decremented accordingly. The next lowest developable site is then evaluated. If the grid component's available capacity is not sufficient to fully utilize the site, that potential link is discarded, and the processing continues to the next record. The supply curve analysis results in a table of the successful links and the resulting costs making that connection, as shown in Figure 2-4.

1. The lowest cost developable site link is identified, and the associated transmission line has sufficient capacity. The site is assigned, and the transmission line and substation available capacities are reduced.
2. The next lowest cost developable link is identified, but the associated transmission line no longer has sufficient capacity. That link is discarded, and processing proceeds to the next lowest cost link in the table for a site that still needs to be assigned.
3. (C and D) The next lowest cost links are identified and assigned successfully, as in (A).

This process continues until all of the developable sites have been assigned to a grid component.

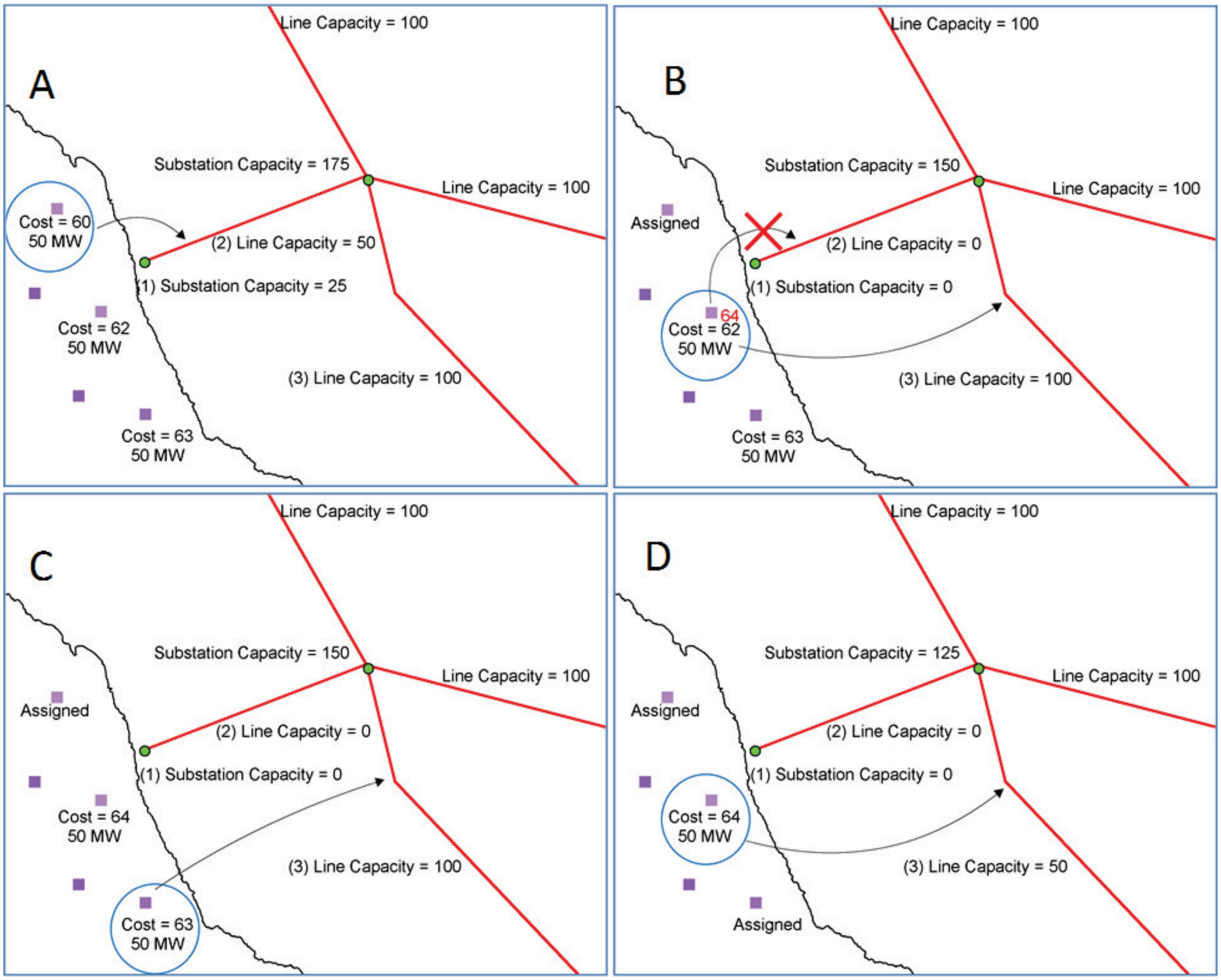

Figure 2-4. Developable site to grid-assignment process

2.3 ReEDS Modeling Assumptions

This section examines the deployment of large quantities of onshore and offshore energy. For the *20% Wind Energy by 2030* report [1], wind capacity deployment was not predetermined, and neither was the mix of onshore versus offshore wind. As such, the model deployed the adequate capacity of both onshore and offshore wind in regions with sufficient resource quality (capacity factor, or CF) to reach the 20% target based on the assumed technology costs and performance data.

The resulting capacity build-out for onshore and offshore wind amounted to 204 GW in 2030, as shown in Figure 2-5. This schedule was used as an input to ReEDS—i.e., the cumulative installed onshore and offshore capacity was enforced in the model as a constraint. Figure 2-6 summarizes the installed offshore wind capacity per year on a national basis. ReEDS then determined the location of that capacity. The schedule was chosen instead of a more compressed timeline to maintain the annual capacity installation detailed in *20% Wind Energy by 2030*. Note that this expansion includes the installation of some plants that predate the issuance of the permits necessary to actually build these plants. Despite this incongruity, these installations are relatively small and could be made up in subsequent years.

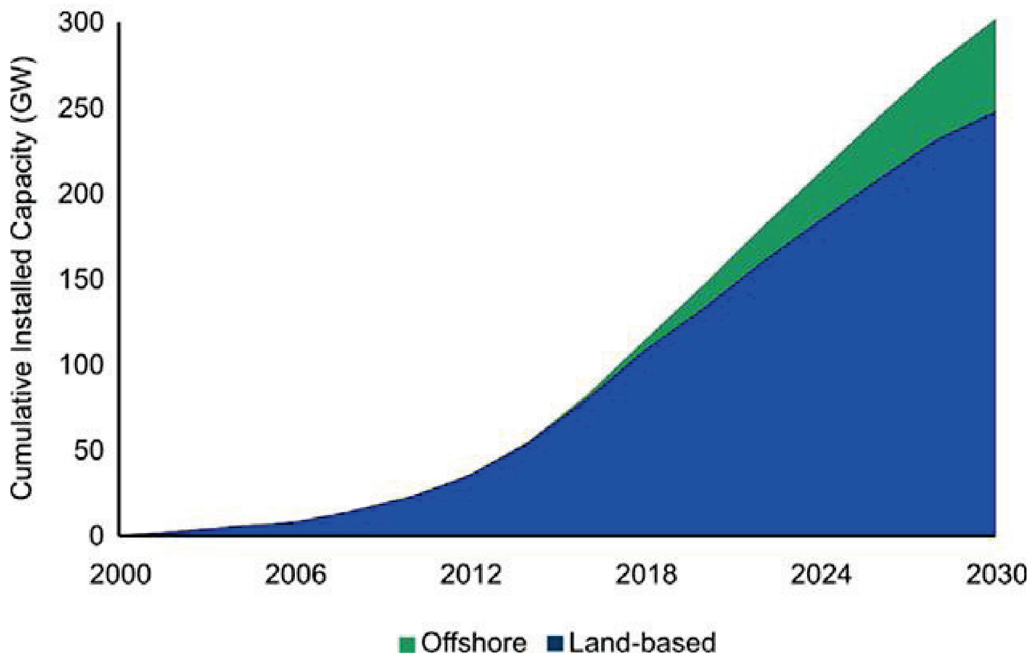

Figure 2-5. Onshore and offshore wind installed in **20% Wind Energy by 2030**

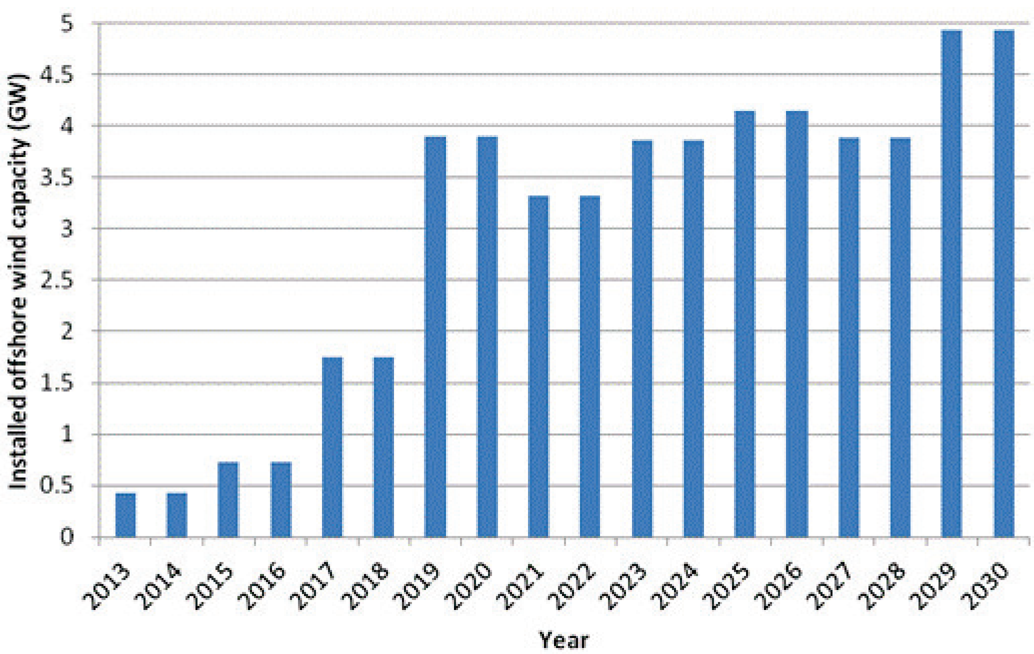

Figure 2-6. Installed offshore wind by year

As a cost-optimization model, ReEDS relies on technology cost and performance projections to comprise its capacity expansion and dispatch decisions. Detailed technology cost and performance assumptions and the broader economic impacts from the ReEDS scenarios are presented in Appendix A, Volume 2 of [3] and [9]. Because the deployment of onshore and offshore wind was predetermined, other assumptions in ReEDS (such as natural gas price projection, technology costs, and demand projections) were not as critical in this case. Parameters such as resource quality or transmission availability were the primary drivers of the deployment results. Natural gas price projections were based on the U.S. Energy

Information Agency's (EIA's) *Annual Energy Outlook 2011*, with an average price of $5.30 per million BTU in 2010 and an elasticity built in with respect to demand.

ReEDS can also take into account renewable portfolio standards (RPSs) set by different states—e.g., by forcing a certain percentage of load to be met by renewables in a state by a given year. These RPSs have a moderate effect on the timing and distribution of the deployment of wind. The most recent published RPS requirements in effect [10] were used in ReEDS. Builds of other renewable sources (photovoltaic, CSP, geothermal, biopower, hydropower) were ignored for simplicity, given that the original *20% Wind Energy by 2030* report did not include other renewables either.

2.4 Deployment Results

The model was solved utilizing the assumptions in the previous sections. Figure 2-7 shows the evolution of installed capacity nationwide, and Figure 2-8 represents the production of energy by generation type. In that figure, load represents bus-bar load. The difference between total production and served load represents transmission losses and energy curtailment.

Onshore and offshore wind schedules were successfully enforced. "Other renewables" included installed capacity (geothermal, biopower, landfill gas, CSP, photovoltaic) that existed in the system at the beginning of the simulation. As discussed in the previous section, no new capacity for these technologies was added. Existing coal and oil-, gas-, and steam-powered plants were gradually retired, although natural gas combined-cycle and combustion turbine units were installed to increase system flexibility and accommodate the large penetration of wind energy.

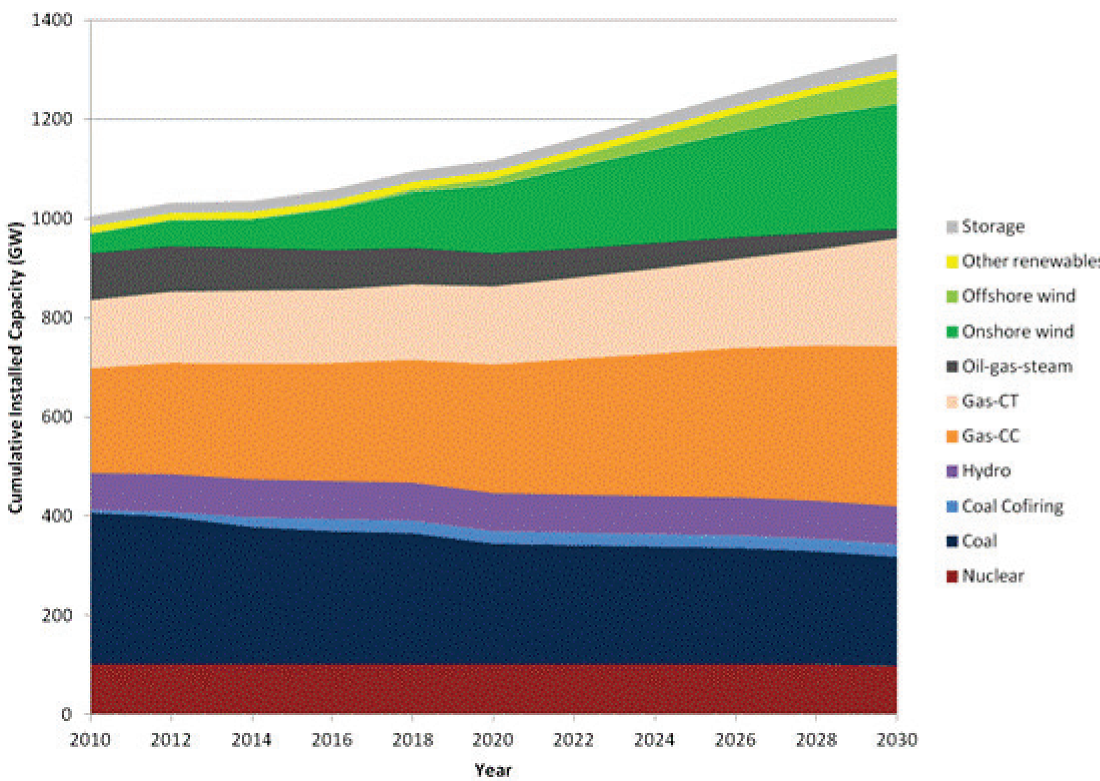

Figure 2-7. Cumulative installed capacity by year

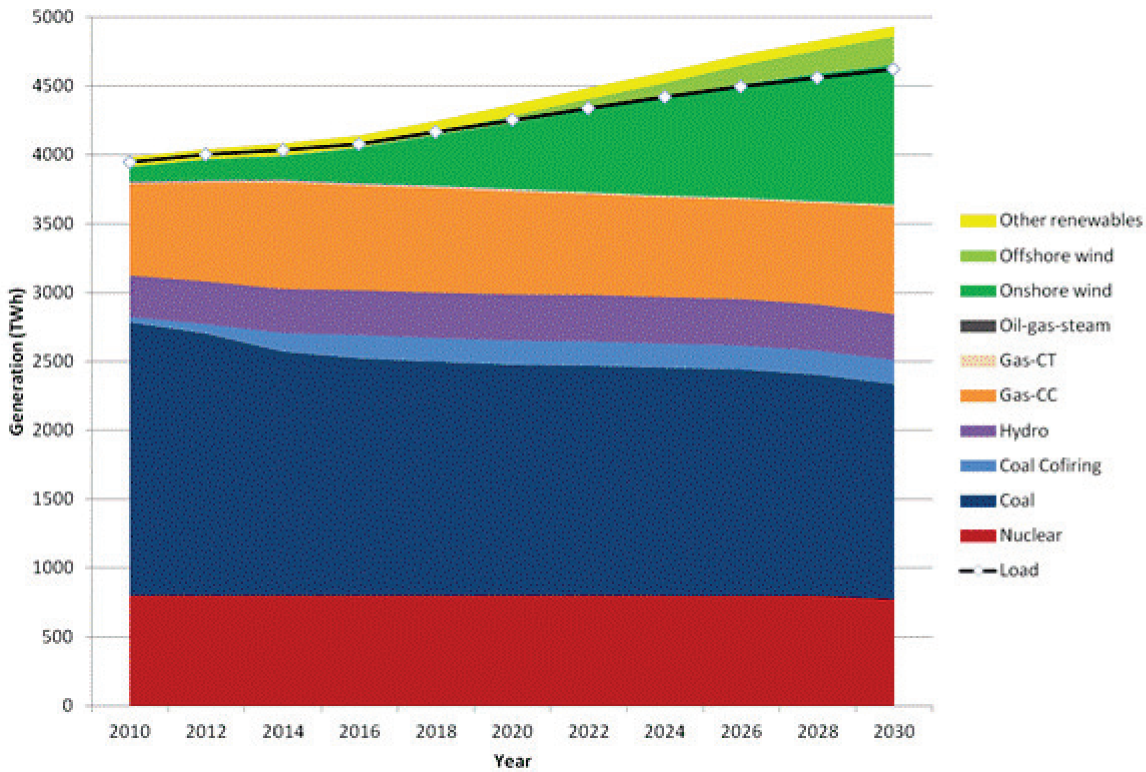

Figure 2-8. Generation by type

Figure 2-9 shows where the 304 GW of onshore and offshore wind were deployed. Onshore wind was heavily installed in the resource-rich Midwest (especially in northern and southeastern Texas, eastern Colorado, and Iowa), Great Lakes (Michigan), and to a lesser extent throughout the Western Interconnection, the Northeast, and Appalachia. Offshore wind deployment was concentrated in the North and Mid-Atlantic, and marginally in the Gulf Coast, Great Lakes, and the northern California/southern Oregon area.

Just as important as the final build-out is the path to reach that point, because it will determine the possible stages to design and install an offshore transmission grid. Figure 2-10 summarizes the installed capacity over time by state. Given that most of the capacity was concentrated in the East Coast, it made sense to focus the design effort around that area. New Jersey and New York were the epicenter of early capacity builds, which were later extended north (mainly to Massachusetts) and south to Maryland, Virginia, and the Carolinas.

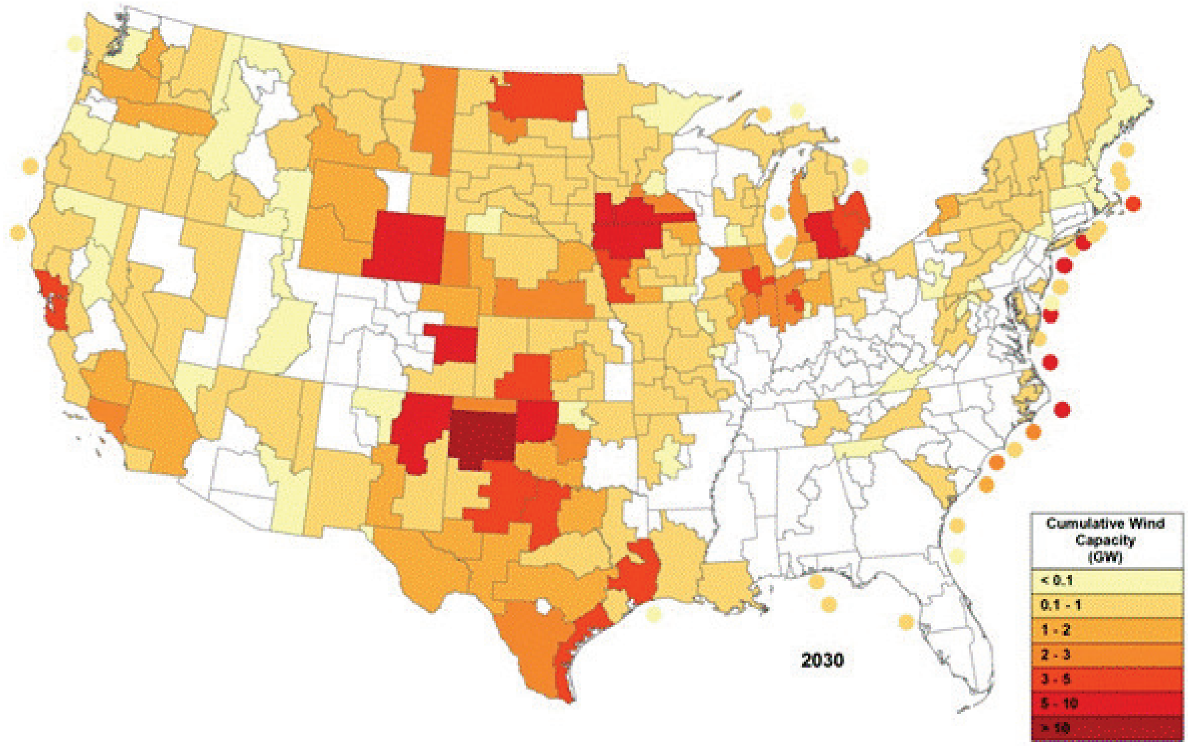

Figure 2-9. Onshore and offshore wind deployed in 2030

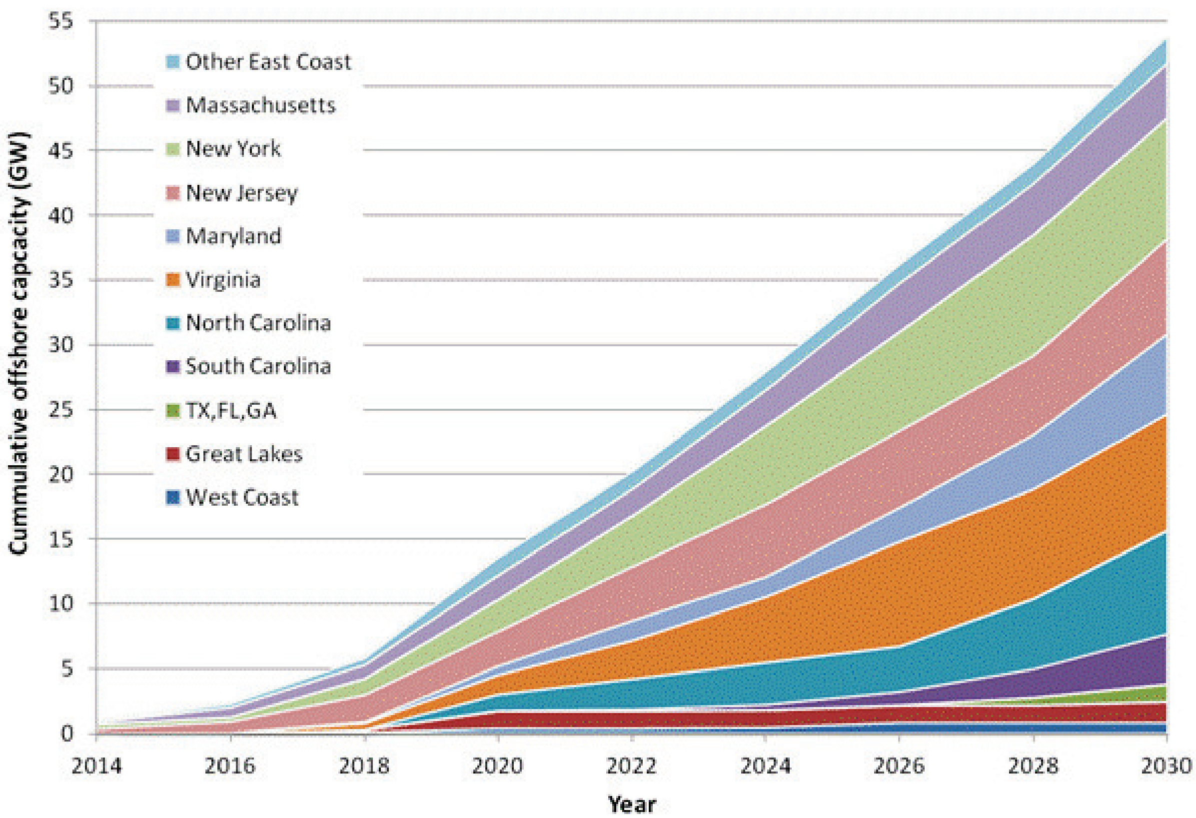

Figure 2-10. Installed wind capacity by state

The geographical resolution in ReEDS allowed for a detailed analysis of offshore deployment. The maps in Figure 2-11 show the two-year increments for the East Coast, where an offshore grid would be most likely to benefit from offshore wind deployment and integration. The first steps of the deployment would occur in the northern portion of the coast, between New Jersey and Massachusetts. It is in that area where the first phase of the grid could be laid out, possibly in the 2018 time frame. In the next few years, deployment would then begin to be more present in Virginia, which could represent a second phase. Finally, Phase 3 would extend to North and South Carolina. Based on the level of deployment, the grid would not continue beyond this point, unless other economic or operational factors were taken into account.

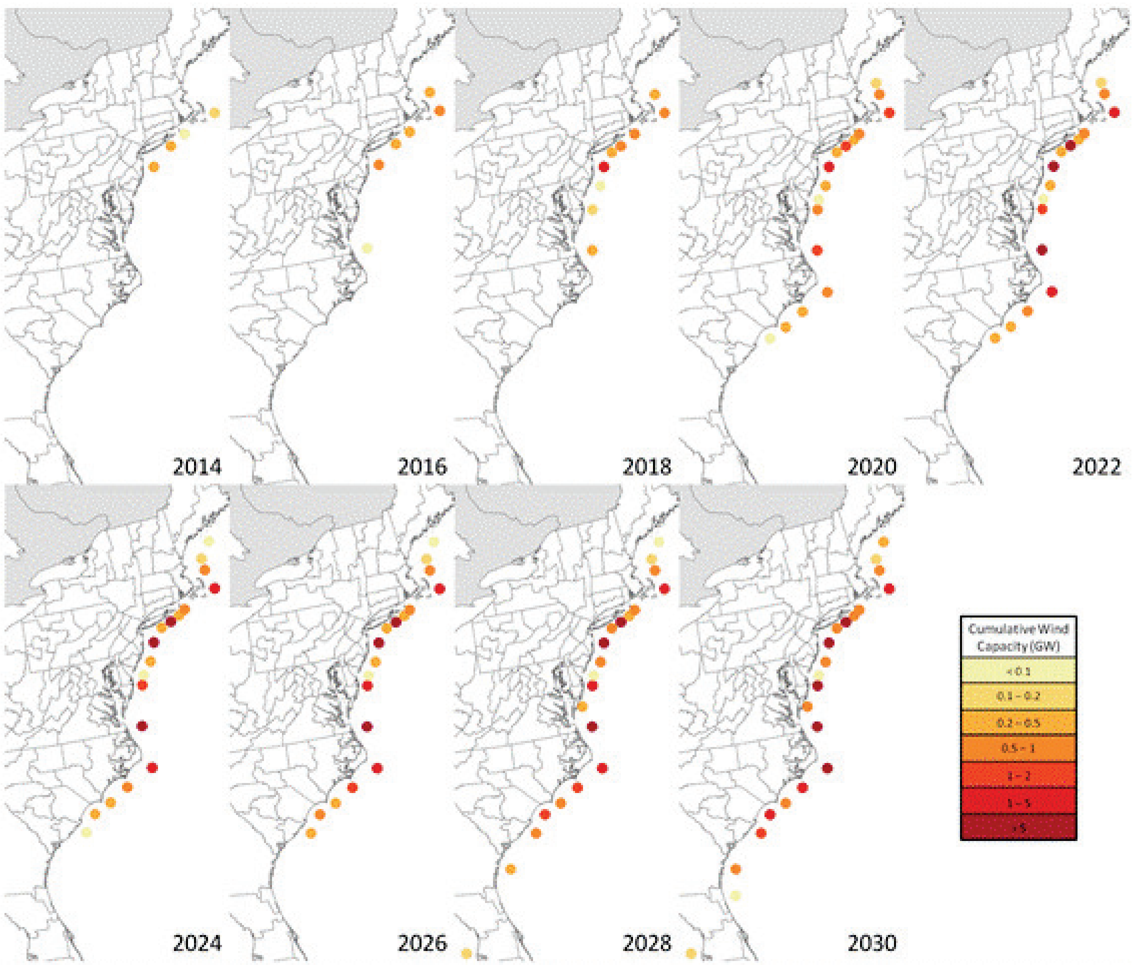

Figure 2-11. Offshore wind build-out for the East Coast

2.5 Factors That Influence ReEDS Deployment Decisions

The following is a list of the main drivers that influence site selection in ReEDS. The run performed for this project forces all offshore resource to compete to be part of the 54 GW of installed offshore wind. This is done through a cost minimization of the system, so that the ultimate reason wind would be deployed in a region is that that it was economically advantageous compared to other regions. (A nationwide constraint of 54 GW of offshore wind capacity by 2030 was applied.)

- **Resource quality**—All potential resources in the country (after applying exclusions) are classified into five CF groups. The average CF for each group evolves over time to represent technology improvement.
- **Capital and operations and maintenance costs**—These are common for all offshore wind.
- **Interconnection cost**—All developable wind potential is assigned a connection cost to the grid, along with other cost adders that depend on factors such as population density, slope, etc. A supply curve is created through a geographic information system process, and it becomes a static input to ReEDS.
- **Transmission cost penalty**—This represents the difficulty of developing new transmission lines in certain portions of the country, based on [11].
- **Variability metrics**—To better capture aggregate variability of the system, correlation statistics are calculated between the power outputs of geographically separated variable generation. In general, greater geographic distance between two wind power plants leads to a lower degree of correlation between power outputs, which decreases the variability of their combined generation. These metrics include capacity value, forecast error, and curtailment.
- **Proximity of wind resources to high load centers.**

Table 2-4 shows some of the parameters listed above for different wind regions in ReEDS. The regions on the left had offshore wind deployed; the regions on the right did not. The table also includes a brief explanation of each row in the table and their net impact on making offshore wind more attractive. Additional parameters can further affect the deployment of offshore wind (e.g., transmission usage and availability, generation mix by area, correlation between load and wind power profiles in the same or different areas), but their effects cannot be quantified as easily. Based on the values shown in the table and further exploration of the inputs and results, it was possible to explain why some areas did not receive offshore wind although others did.

- **Texas (Region 174)**—Connection costs and curtailment were high, although capacity value was low (compared to Region 256).
- **Ohio (Region 234)**—A transmission cost penalty, low capacity value, and high curtailment were present.
- **Delaware (Region 318)**—Connection costs were high. This was because the best resource in Delaware is either excluded or is found several miles off the coast, as confirmed by a visual inspection of the resource map. The transmission penalty was also high.
- **Pennsylvania (Region 320)**—A transmission cost penalty was present.
- **New York (Region 333)**—There was a high connection cost and transmission penalty.

Based on the assumptions used in this model, the proposed build-out represented the least-cost option, but the process took into account important variability factors in the optimization. The regions with little or no installed capacity were simply less valuable to the system than those that were actually installed.

Table 2-4. Parameters That Influence Deployment Decisions for Areas with and Without Wind Installed in 2030

	Offshore Wind Installed					No Offshore Wind Installed				
Wind Region[a]	***219***	***256***	***270***	***294***	***330***	***174***	***234***	***318***	***320***	***333***
State[a]	***IN***	***TX***	***FL***	***NC***	***NJ***	***TX***	***OH***	***DE***	***PA***	***NY***
Onshore capacity (GW)[b]	0.12	3.03	0	0.48	0	3.66	0.45	0	0	1.95
Offshore capacity (GW)[b]	0.29	0.06	0.29	5.02	6.82	0	0	0.03	0	0
Offshore installed in 2030 (GW)[b]	0.29	0.06	0.29	1.67	1.23	0	0	0	0	0
Capacity factor (%)[c]	48.3	44.5	38.4	48.3	48.3	52.3	48.3	48.3	48.3	44.5
Connection cost ($/kW)[d]	78.2	59.1	52.7	166.4	307.4	208.2	39.9	377.8	125.0	915.2
Transmission penalty (multiplier)[e]	1	1	1	1	3.56	1	1.58	3.56	1.58	3.56
Capacity value (%)[f]	16.7	17.2	17.2	21.8	22.2	15.8	16.7	22.2	22.2	27.2
Forecast error (fraction)[g]	0.039	0.040	0.040	0.035	0.046	0.094	0.039	0.046	0.046	0.041
Curtailment (%)[h]	6.7	4.1	4.1	7.8	6.0	8.3	6.7	6.0	6.0	3.4

a. Wind region in ReEDS (see Figure 3-1 and [1]) and region it belongs to

b. Cumulative onshore and offshore wind capacity installed at the end of 2030, and offshore capacity installed in 2030

c. CF for additional offshore capacity (higher is better)

d. Cost to connect to the grid for additional offshore capacity (lower is better)

e. Penalty applied as a multiplier to transmission cost for additional offshore capacity (lower is better)

f. Capacity value provided by additional offshore capacity (higher is better).

g. Parameter that determines the forecast error for additional offshore capacity, which increases the need for regulation in the system (lower is better)

h. Fraction of potential that is curtailed for additional offshore capacity (lower is better)

2.6 Section References

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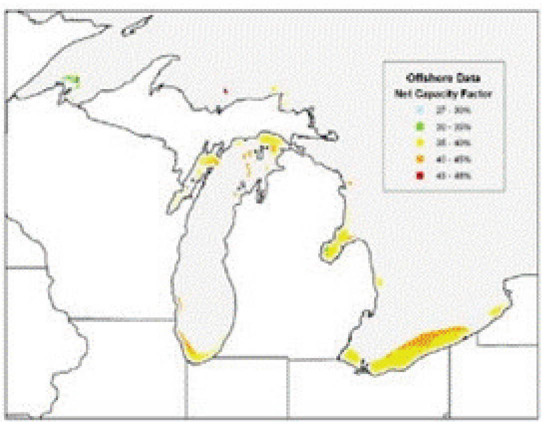
3.0 WIND PRODUCTION PROFILE DEVELOPMENT

AWS Truepower supplied 10-minute wind production profiles for hypothetical offshore wind projects in the Great Lakes, Atlantic Ocean, Gulf of Mexico, and Pacific Ocean. This data set is meant to expand upon the wind profiles developed for EWITS [1]. Siting the most likely wind projects to be developed, modeling the historical wind patterns throughout the study years (2004–2006), synthesizing wind production profiles at the selected sites, and analyzing the variability of the simulated wind power comprised the work.

3.1 Background

AWS Truepower simulated onshore and offshore wind production profiles for hypothetical sites in the Eastern Interconnection for EWITS. Offshore areas considered included the Great Lakes and the Atlantic Ocean from Maine to North Carolina. Onshore data represented site layouts; whereas offshore areas were represented as 2-km by 2-km grid cells with 20 MW of generation capacity each (i.e., a mean density of 5 MW/km^2). Areas were considered within a maximum water depth of 30 m and a minimum distance from shore of 8 km (5 mi). Offshore areas meeting these criteria that were also outside federal or state protected areas and had an estimated annual net capacity factor (NCF) of at least 32% were selected. The resulting list contained 10,000 offshore "sites" representing areas that could potentially be developed with offshore wind, as shown in Figure 3-1.

The current study reexamined EWITS offshore areas and expanded the study area to include the Atlantic Coast from Maine to Florida, the Gulf of Mexico, and the Pacific Coast. Potential areas excluded from development were expanded to include shipping lanes, dumping grounds, anchorage areas, obstructed areas, and other areas described in more detail below. The site selection was refined to include potential site layouts instead of 2-km grid cells. The composite power curve used for EWITS was updated to reflect more productive technologies, requiring modification of the site density and wake-loss assumptions. Finally, results from the ReEDS model were used to aid the site selection process.



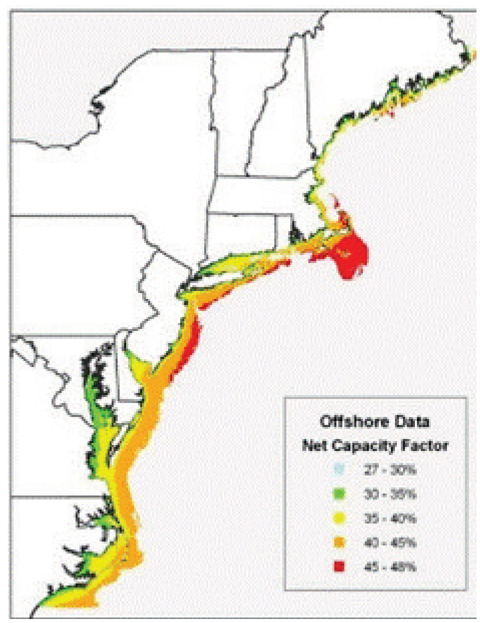


Figure 3-1. EWITS offshore sites

3.2 Site Selection

The goal of the site selection process is to identify likely areas of offshore wind development within 80 km (50 mi) of the Atlantic, Gulf, and Pacific coasts as well as within the Great Lakes based on offshore wind resources, areas excluded from development, and COE. The ReEDS model defined capacity targets for several offshore "zones" for the years from 2014 to 2030. The 2030 targets were used for this portion of the study. The selection process seeks to site potential wind farms within the ReEDS zones, meeting and/or exceeding the ReEDS model targets so that a variety of scenarios may be studied. The study team determined that the project sizes should generally range from 300 MW to 1,000 MW.

By combining the characteristics of several commercial-scale turbines normalized to their rated capacity (Siemens SWT-6.0-154, Alstom Haliade 150-6 MW, and AMSC SeaTitan 10 MW-190), a composite offshore turbine was derived. The composite turbine is an IEC Class I machine with a hub height of 100 m and rotor diameter of 165 m. Using a 10 x 10 rotor-diameter spacing resulted in a site density of 2.75 MW/km^2. Previous work at AWS Truepower and by [2] determined that it takes 15 km to 20 km for the winds downstream from offshore turbine arrays to recover to within 1% to 2% of the free-stream wind speed. Based on these results and the larger turbines assumed in this study, it was determined that sites should be spaced at least 20 km apart.

Table 3-1. Exclusions and Constraints of Offshore Wind Power

Excluded Area	Additional Area Buffer
Anchorage area	300 m
Beacon	30 m
Buoy	30 m
Cables	300 m
U.S. Department of Defense Wind Energy Exclusion Areas (available in Atlantic only)	None
Dumping ground/dredging sites	300 m
Fairway shipping channel	1.85 km (1 nmi)
Ferry route	0.93 km (0.5 nmi)
Fog signal	30 m
Lights	30 m
Offshore platform	30 m
Pipe	300 m
Precautionary area	None
Shipping lane	1.85 km (1 nmi)
Shipping traffic lane	1.85 km (1 nmi)
Shipping traffic lane boundary	1.85 km (1 nmi)
Shipping traffic separation zone	1.85 km (1 nmi)
Wreckage areas	30 m
Habitat areas	None
Marine sanctuaries	None
Other (e.g., salt mines, state economic zones)	None

Areas to be excluded from development were compiled from the National Oceanic and Atmospheric Administration (NOAA) Marine Cadastre [3] and exclusion layers developed by Black and Veatch for the ReEDS model. Effort was made match NREL constraints to ensure selected sites accurately expand on ReEDS model results. Marine sanctuaries [4] and U.S. Department of Defense Wind Energy Exclusion Areas [5] were later added at the request of the study team. A listing of excluded areas is given in Table 3-1.

During the preliminary site selection, it was discovered that some excluded areas overlapped some areas being considered by the Bureau of Ocean Energy Management (BOEM) for offshore wind development [6]. It was determined that any BOEM wind planning area, wind energy area (WEA), or area being considered at the state level would supersede any exclusion and that at least one hypothetical wind farm would be placed within each of these areas. Exclusions within these areas were used only to separate large planning areas into reasonable site sizes. Additionally, wind resource areas identified by the Michigan Great Lakes Wind Council [7] were designated as sites, regardless of excluded areas or size restrictions.

At the suggestion of NREL, the 4C Offshore database [8] was also consulted to identify projects in planning phases. This database includes proposed offshore project areas in the Great Lakes, Gulf of Mexico, and Pacific Ocean that are not included in the BOEM areas. Projects listed in this database were considered according to their status as follows:

- Cancelled—ignored
- Failed—ignored
- Dormant—ignored
- Concept/early planning—site placed in general vicinity if listed capacity is greater than 300 MW
- Consent application submitted—site placed to match listed location and capacity if possible
- Consent authorized—site placed to match listed location and capacity regardless of other considerations (e.g., exclusions, size constraints)

A 20-km buffer of any sites selected in the above processes was created to reduce the impact of neighboring wind farms, and the remaining area was used to select additional potential sites based on the wind resource. This buffer was applied without regard to prevailing wind direction.

Based on AWS Truepower's long-term historical model runs and wind speed distributions, a seamless map of 100-m wind speeds at 200-m horizontal resolution was generated for offshore areas within 80 km of the U.S. coasts. The composite turbine and simulated wind speeds were used to construct a national offshore gross capacity factor map. Environmental losses were estimated by region (Atlantic Ocean, Gulf of Mexico, Great Lakes, and Pacific Ocean) and applied to create a NCF map (Figure 3-2).

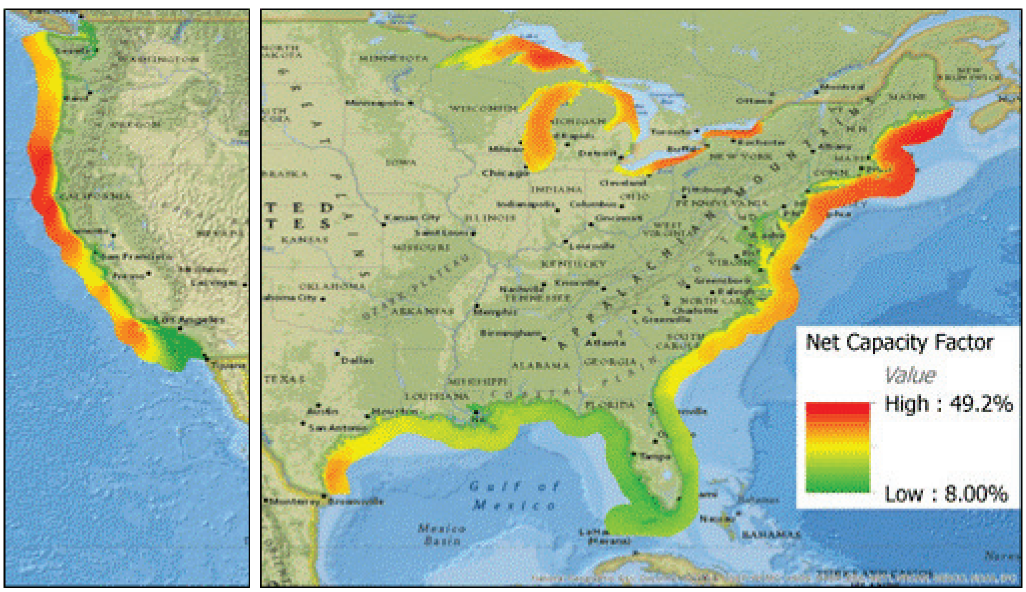


Figure 3-2. National offshore wind NCF map

The NCF map and areas excluded from development were used in a geographic information system (GIS)-based algorithm that seeks to minimize the COE while assigning enough near-contiguous area to support projects of a range of sizes greater than 300 MW. The objective of the site screening was to supplement the sites selected by the processes above by selecting additional sites in areas of strong wind resource both within and outside of ReEDS zones with capacity targets to reach approximately 100 GW of total sites. Initial results were modified manually to fulfill ReEDS targets while maintaining site separations and size ranges, but the size and separation requirements were relaxed when necessary.

The initial screening placed the Great Lakes sites almost entirely in deep water. Based on current development trends [9] and input from NREL, the selection was initially limited to water depths less than 60 m. Sites selected at shallower depths were then buffered, and the screening program was run again with all water depths considered. This process resulted in a wider variety of site depth and distance to shore. The same methodology was followed in the Pacific Ocean, where the water depth also increased rapidly.

The site selection process identified 290 sites totaling more than 185 GW. The COE for each site was calculated in the following manner using cost estimates provided by NREL using $2012:

$$COE = \frac{FCR \times (CC + TC + IC)}{8760 \times CF \times P} + OM$$

where,
FCR = fixed charge rate (12.8%)
CC = capital cost ($3,902,019/MW ≤ 30 m water depth; $4,810,761/MW > 30 m water depth)
TC = transmission cost ($1597.20/MW-mi)
IC = interconnection cost ($27,402.10/MW)
CF = net average plant capacity factor
P = plant nameplate capacity
OM = operations and maintenance ($45/MWh)

Mean water depth (based on [10]) and distance to land (calculated as a straight-line distance to the nearest onshore point) were calculated for each site. The study team determined that a cost multiplier designed to represent the difficulty of adding new transmission in each region was too aggressive, making Florida sites more attractive than East Coast sites, and it was ultimately removed from the COE calculation.

Sites were then ranked by COE. The lowest cost sites were retained, ensuring that the ReEDS target capacities were fulfilled in each ReEDS zone. The maximum COE of any site fulfilling a ReEDS target was $258.5/MWh; all sites with a COE lower than this threshold were retained. This ranking reduced the site list to 209 sites totaling 134+ GW, with at least one site offshore each state (Figure 3-3). Although this selection method resulted in a total capacity well in excess of some ReEDS zones targets, it was determined that this was the most objective way to reduce the preliminary sites to only the most economically viable. AWS Truepower provided a map of all sites along with a table of their relevant characteristics (e.g., area depth, CF) to the study team in April 2013 (see Appendix A—Table of Selected Sites). The sites were also summarized by region (Table 3-2). Lowest cost sites fulfilling the 54 GW ReEDS capacities for each zone were also noted in Appendix A, but it was ultimately determined that ABB would reduce the sites to the 54 GW by ranking all sites by COE and retaining the lowest cost sites without regard to ReEDS capacities.

Figure 3-3. Map of 209 selected potential offshore wind projects (red circles) along with ReEDS zones with (yellow) and without (blue) capacity targets

Table 3-2. Summary of Selected Sites by Region

Region	No. Sites	Total Capacity (MW)	Mean Size (MW)	Mean Depth (m)	Mean Distance (km)	Mean NCF	Mean Wind Speed (100 m, m/s)	Mean COE ($/MWh)
Atlantic	84	68,229	812	-54.3	40.6	0.401	8.642	207.71
Gulf	30	16,211	540	-21.8	35.2	0.334	7.764	229.20
Lakes	58	25,411	438	-89.8	25.1	0.393	8.467	221.40
Pacific	37	24,577	664	-1143.0	47.1	0.416	9.136	219.06
Total	209	134,428	614	-327.2	37.0	0.386	8.502	219.34

3.3 Weather Model Runs

AWS Truepower employed the Mesoscale Atmospheric Simulation System (MASS) [11], a proprietary weather prediction model specifically tuned for near-surface wind and irradiance prediction, to simulate historical wind speed, direction, air pressure, and turbulence kinetic energy necessary to synthesize offshore wind production for the study years from 2004 to 2006. The model was configured as in EWITS to ensure maximum consistency between the EWITS and NOWEGIS simulations (Table 3-3).

Table 3-3. Mesoscale Model Configuration

Item	Description
Model	MASS v. 6.8
Initialization data source	NCEP/NCAR Global Reanalysis
Data assimilated	Rawinsondes, standard surface observations, buoys
Sea surface temperatures	MODIS (1-km satellite based)
Terrain and land cover (2-km grids only)	USGS 30-m NED and 30-m NLCD
Cumulus scheme (30-km and 8-km grids only)	Kain-Fritch
Spin-up	12 hours before start of valid run
Output frequency	10 minutes
Variables stored	Wind speed and direction, temperature, pressure, turbulence kinetic energy at 5 heights (10 m to 200 m above ground), skin temperature, relative humidity, solar radiation, and precipitation
Simulation period	January 1, 2004 to December 31, 2006

The reanalysis data used to initialize the simulations are on a relatively coarse grid (approximate 210-km spacing). To avoid generating noise on the simulation boundaries that can result from large jumps in grid cell size, MASS was run using nested grids of successively finer horizontal resolution until the desired grid scale was reached. In this configuration, the outer grid provides the initial guess fields and updated lateral boundary conditions for each subsequent nest of an inner grid. EWITS employed nested grids of 30 km, 8 km, and 2 km horizontal resolution covering the Great Lakes and Atlantic Coast down to North Carolina. Following EWITS, the remainder of the Atlantic Coast as well as most of the Gulf Coast (excluding Florida) was modeled with this nesting scheme down to 2-km spatial, 10-minute temporal resolution. Because of schedule and budget constraints, it was determined that the innermost nest in areas offshore Florida and the Pacific Coast where offshore development is less likely should be 8 km. Figure 3-4 shows the configuration of the innermost EWITS and NOWEGIS mesoscale model grids.

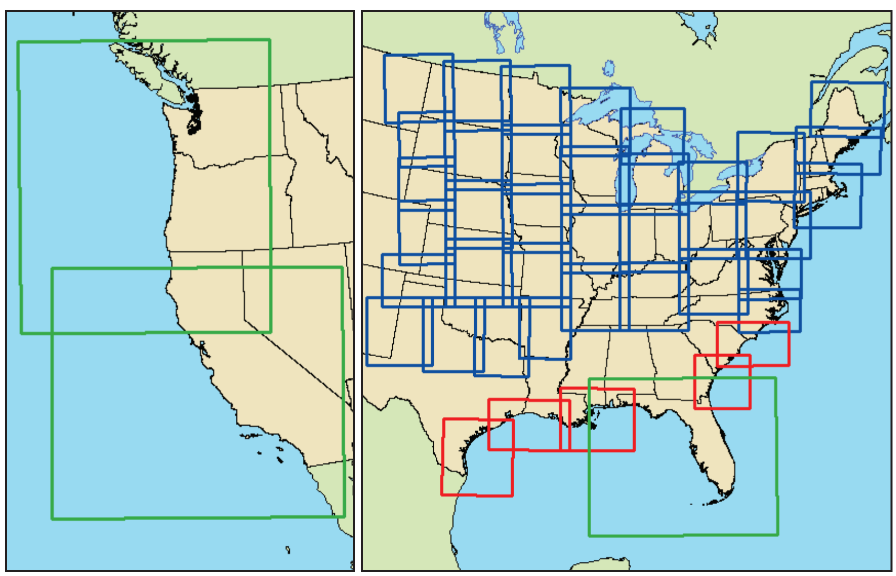


Figure 3-4. Mesoscale model grid configuration. Blue rectangles denote 2-km EWITS grids, red are 2-km NOWEGIS grids, and green are 8-km NOWEGIS grids.

3.4 Synthesis of Wind Production Profiles

The historical model runs were used to synthesize wind power production profiles at the location of each of the selected sites for the full 2004 to 2006 study period. Time series of wind speed, wind direction, temperature, and turbulence kinetic energy were extracted from each model grid cell corresponding to a potential site. In locations where 2-km and 8-km grids overlapped, data from the 2-km grid was used when possible.

To refine the wake loss assumptions for future offshore sites of these sizes, AWS Truepower ran its openWind software [12]. Tests were run with the 7.5-MW composite turbine for areas offshore California, Texas, and Virginia. Sample sites ranged from 650 MW to 1,165 MW, with wind roses varying from unidirectional to multimodal. As a result of these tests, the wake loss assumption for this study was increased from 4% to 9% to 6% to 13%. The electrical loss was reduced to 1.5% to include only up to the offshore substation.

The process of simulating net power production at each offshore site follows the methodology in [1] with updates for the composite power curves and loss assumptions:

1. Modeled wind speeds were scaled to AWS Truepower's validated 200-m offshore wind maps.
2. Wind speeds were adjusted for wake losses by wind direction.
3. Winds were further adjusted by the modeled turbulence kinetic energy to reflect the impact of gusts.
4. The 7.5-MW composite power curve was adjusted for air density and applied to the wind speeds.
5. A time filter was applied to mimic the effect of spatial averaging throughout a wind farm.
6. Availability and electrical losses were applied to simulate net power.

The model output was compared to available offshore surface wind measurements to determine whether any adjustments were necessary. For this exercise, 25 offshore stations from the National Data Buoy Center [13] with monitoring heights greater than 20 m and data available during the study period were identified. All stations were located in the Great Lakes, Atlantic Ocean, and Gulf of Mexico; no such sites were available in the Pacific Ocean. Some of these sites were ultimately discarded from the analysis because of their proximity to the coast and/or seasonal data reliability issues, leaving 13 publicly available stations for model adjustment and validation (Figure 3-5; Table 3-4). These data were sheared from a monitoring height to 100 m based on the MASS shear coefficient at each location so that the data could be compared to modeled data at 100 m. Modeled data were then adjusted to observed diurnal patterns from these stations based on a correlation-weighted adjustment.

Wind speeds were modeled at the location of the 13 measurement stations and compared at 100 m. Only the concurrent period of record was compared, and missing periods in measurements were removed from the modeled results to ensure fair comparison. The predicted mean wind speed at 100 m was on average 0.25 m/s, or 2.6% lower than the observed mean; the standard deviation of the biases was 0.55 m/s, or 6.4% of the observed mean. The model bias did not seem to be regionally based. Results of the validation at each individual station are presented in Table 3-4, along with the mean bias and the standard deviation of the biases across the full 13-station sample. As expected, the predictions agreed well in open water, with TYBG1 and GSLM4 as the largest outliers. Mean measured wind speeds during the period at TYGB1 were greater than 10 m/s; whereas measurements at SKMG1 and SPAG1 (40 and 67 km away, respectively) were between 8 m/s and 8.5 m/s. Although it is possible that TYBG1 experiences higher winds because of Gulf Stream interactions, it is also possible that measurements at this station may be artificially high. Excluding results at TYBG1, the mean bias reduced to -0.14 m/s, or 1.5% of the observed mean speed; whereas the standard deviation of the biases dropped to 0.40 m/s, or 5.2% of the averaged wind speed measured at 100 m. No effort was made to correct for measurement error.

Figure 3-5. Stations used in the model adjustment and validation

Table 3-4. Stations Used in the Model Adjustment and Validation

Station	Name	Region	Lat.	Long.	Anemom. Height (m)	Period of Record	Bias (m/s)
FWYF1	Fowey Rock	Atlantic	25.5910	-80.0970	43.9	2004-2006	-0.41
TYBG1	U.S. Navy Tower R8	Atlantic	31.6330	-79.9250	34	2004-2006	-1.60
SPAG1	U.S. Navy Tower R2	Atlantic	31.3750	-80.5670	50	2004-2006	-0.10
BUZM3	Buzzards Bay, MA	Atlantic	41.3970	-71.0330	24.8	2004-2006	-0.55
ALSN6	Ambrose Light	Atlantic	40.4500	-73.8000	29	2004-2006	-0.22
CHLV2	Chesapeake Light	Atlantic	36.9100	-75.7100	43.3	2004-2006	-0.36
SKMG1	U.S. Navy Tower M2R6	Atlantic	31.5340	-80.3236	50	2004-2006	-0.28
SGOF1	Tyndall AFB	Gulf	29.4070	-84.8630	35.1	2004-2005	0.08
SANF1	Sand Key	Gulf	24.4540	-81.8770	45.4	2004-2006	0.25
SMKF1	Sombrero Key	Gulf	24.6280	-81.1110	48.5	2004-2006	-0.34
BURL1	Southwest Pass	Gulf	28.9050	-89.4280	30.5	2004-2006	0.03
GSLM4	Gravelly Shoals Light	Lakes	44.0180	-83.5370	24.7	2006	0.81
ROAM4	Rock of Ages	Lakes	47.8670	-89.3130	46.9	2004-2006	-0.64
						Average	-0.25
						Stdev	0.55

The modeled and observed diurnal, seasonal, and annual wind speeds, as well as the frequency distribution of hourly changes in wind speed, were examined at each site. Results of a detailed comparison for a station in the Atlantic, Gulf, and Great Lakes are given in Figure 3-6 to Figure 3-8. The comparisons indicate that the model generally captures annual, monthly, and diurnal patterns in wind speeds well. The model slightly underpredicts cool season wind speeds at stations such as Chesapeake

Light and Rock of Ages, contributing to annual mean speeds lower than observed. The modeled wind speed variability matches the observed quite well, with a slight underprediction of modeled variability, likely because the model represents wind speeds throughout a 2-km grid cell versus the measurements at a single point.

Although the modeled data were adjusted using the most representative data possible, it should be stressed that the mean wind speed at any particular location may depart from the predicted value. Errors may reflect problems with either the simulation, observations, or both. Note that uncertainty exists in comparing measured data sheared from below 50 m to 100 m. Additionally, several of the selected stations utilize anemometers installed on lighthouses, islands, and offshore platforms. Such structures may impact the measured wind speeds.

The mean speeds were scaled to AWS Truepower's 200-m offshore wind speed maps, which have been adjusted and validated in conjunction with NREL against measurements from tall towers, standard meteorological stations, instrumented buoys, and remotely sensed data such as satellite-based sea surface winds. The map validation procedure is intended to remove areas of spatially correlated biases, rather than eliminate the bias at any particular site. General information about the map validation procedure and results are given in [14]. With these considerations in mind, it was determined that the model sufficiently captured annual, diurnal, and monthly wind speed characteristics as well as variability characteristics at individual point locations.

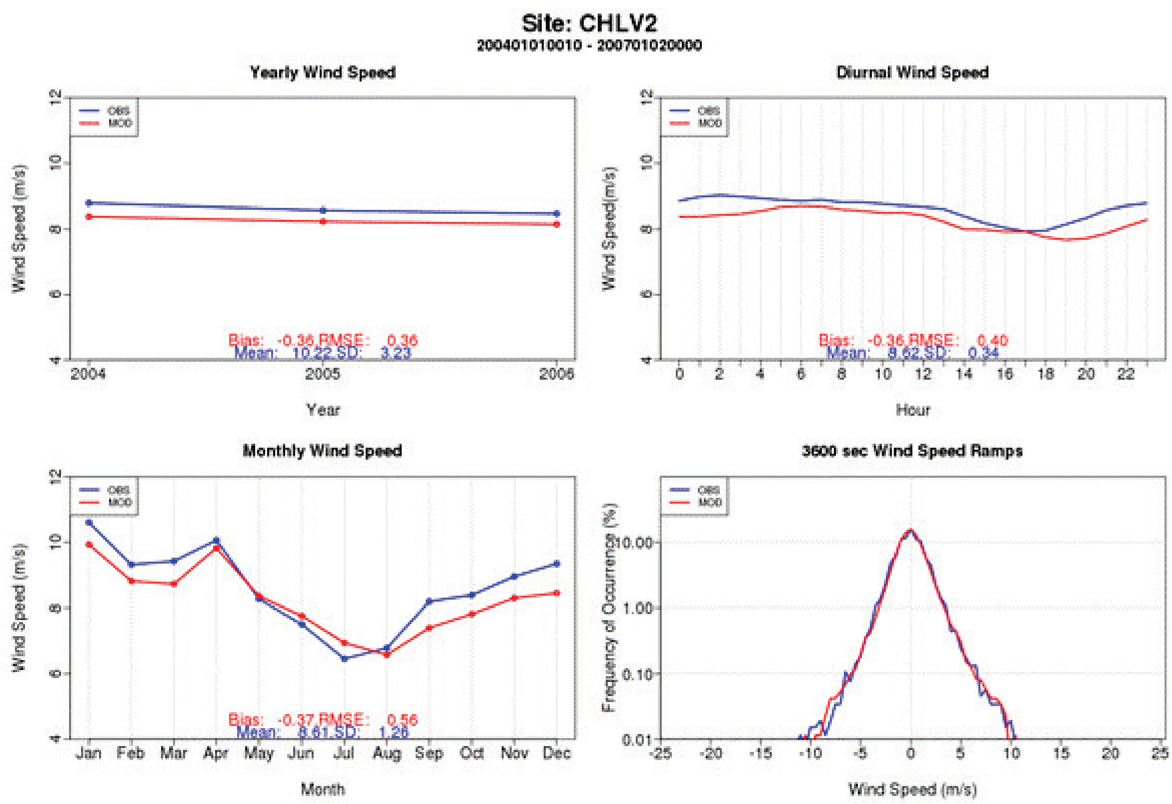


Figure 3-6. Modeled (red) and measured (blue) annual, monthly, and diurnal mean wind speeds as well as the frequency distribution of hourly wind speed changes at Chesapeake Light, Virginia.

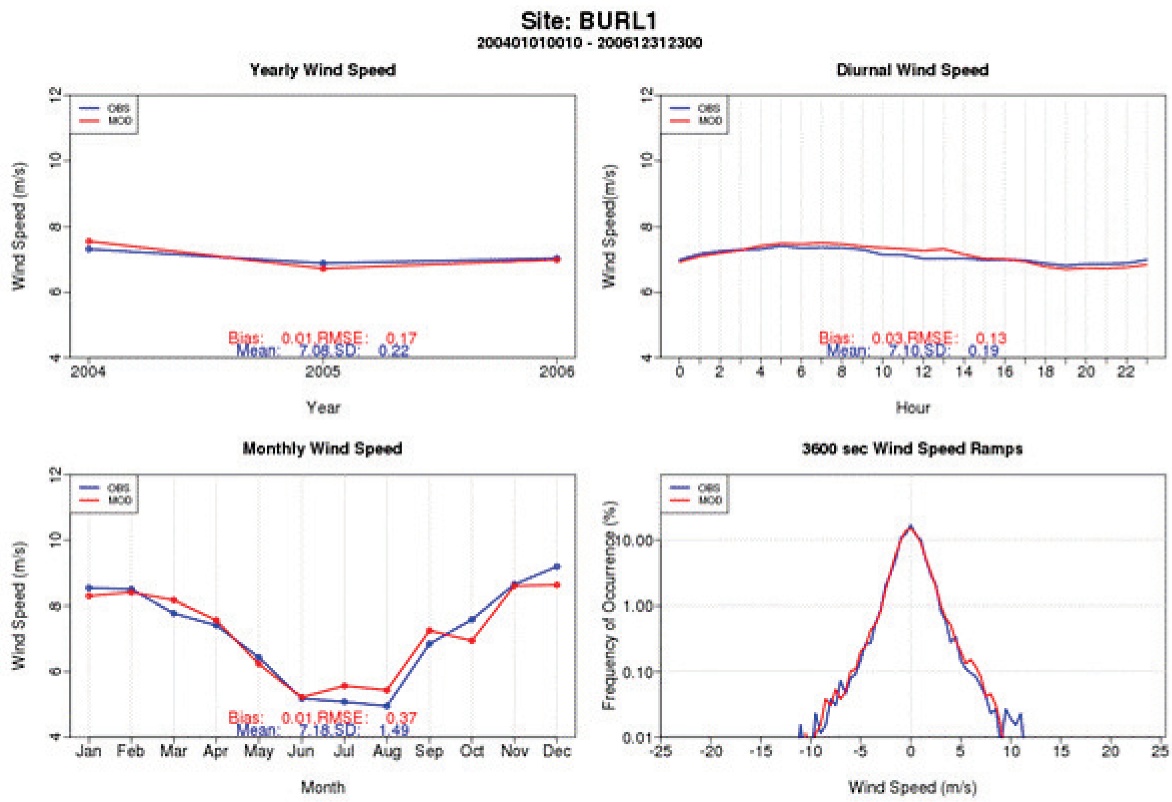


Figure 3-7. As in Figure 3-6, but for Southwest Pass, Louisiana.

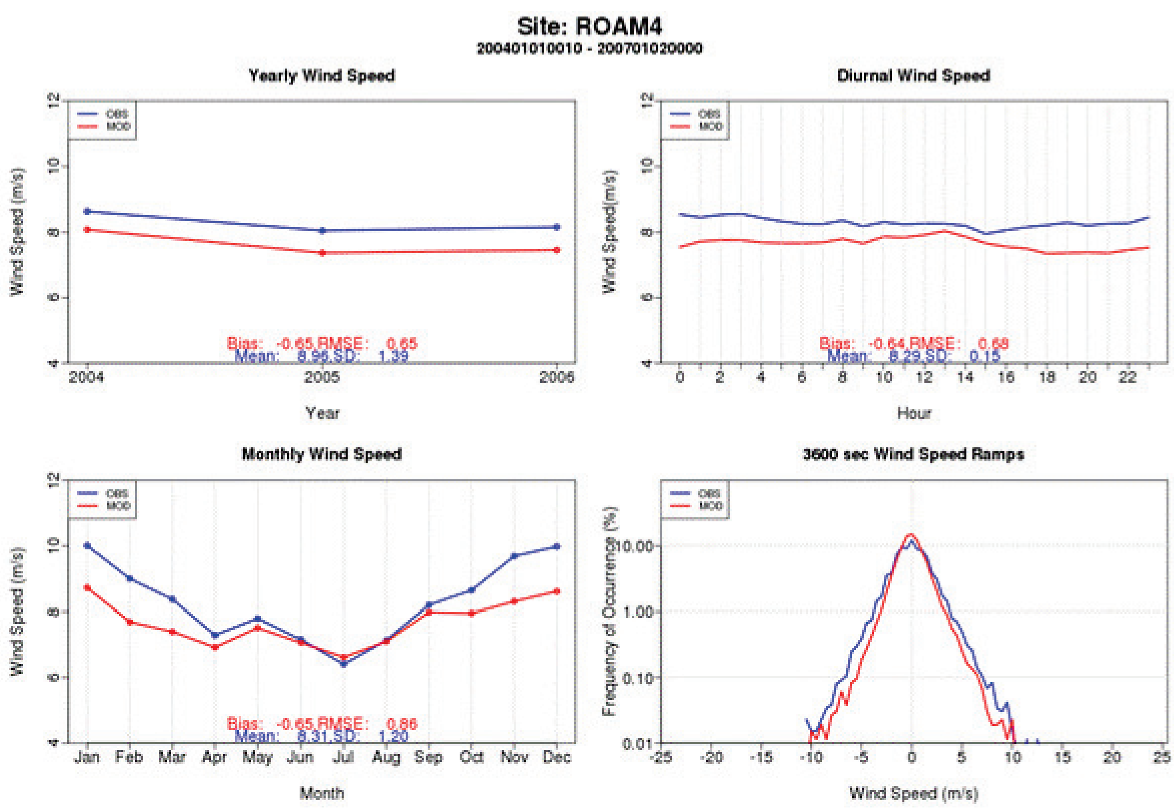


Figure 3-8. As in Figure 3-6, but for Rock of Ages, Minnesota.

Although data modeled at individual points represented realistic patterns, spurious ramping patterns in which more variability was observed after 0000 UTC and 1200 UTC as a result of the ingestion of measured data into the model every 12 hours (Figure 3-9) were noted at modeled offshore sites. A correction previously developed for the Eastern Renewable Generation Integration Study (ERGIS) to reduce this phenomenon for regional site aggregates was applied [15]. This correction effectively removed the spurious patterns for aggregates of several sites, but the pattern remained at individual sites. A correction for individual sites previously developed for the Oahu Wind Integration and Transmission Study [16] was also insufficient for this study because of the large site size (300 MW to 1,000 MW compared to 10 MW to 400 MW). Instead, a new correction was developed in which the diurnal wind speeds were interpolated throughout the hour spanning the data injection times (twice daily), and the mean diurnal standard deviation of the 10-minute changes in wind speed were adjusted toward the mean standard deviation of all 10-minute changes in wind speed on a rolling 1-hour basis. Resulting wind speeds were then scaled back to the 200-m wind map. Diurnal mean net power and changes in net power before and after the adjustment are shown in Figure 3-10. The correction removes the spurious increase in mean wind speeds after 0000 UTC and 1200 UTC as well as the resulting increases in net power ramps.

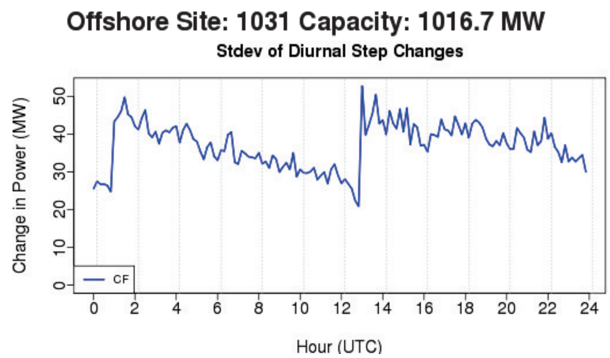


Figure 3-9. Standard deviation of diurnal mean 10-minute ramps in net power (MW) at a sample site

After the individual site correction was applied, it was determined that the aggregate correction was still necessary to correct the problem when several sites throughout a region were combined. The aggregate correction was applied by MASS grid (Atlantic and Gulf), lake (Great Lakes), or state (Pacific), resulting in a satisfactory mean diurnal profile for regional or overall aggregates of sites (Figure 3-11).

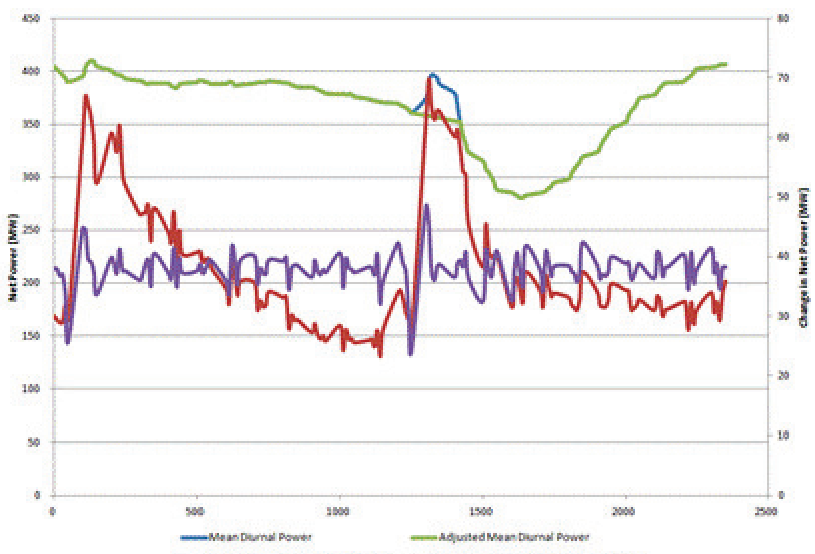


Figure 3-10. Diurnal data correction developed for NOWEGIS. Mean diurnal net power before and after the correction are shown in blue and green, respectively. The diurnal mean standard deviations of 10-minute changes in net power before and after the correction are shown in red and purple, respectively.

With these adjustments, the final 2004 to 2006 data set of 10-minute wind speed, wind direction, and net power at 100 m for each of the 209 sites was delivered as a set of comma-separated files in August 2013. At NREL's request, gross capacity factor, NCF, losses, and annual net energy production were summarized in the header of each file.

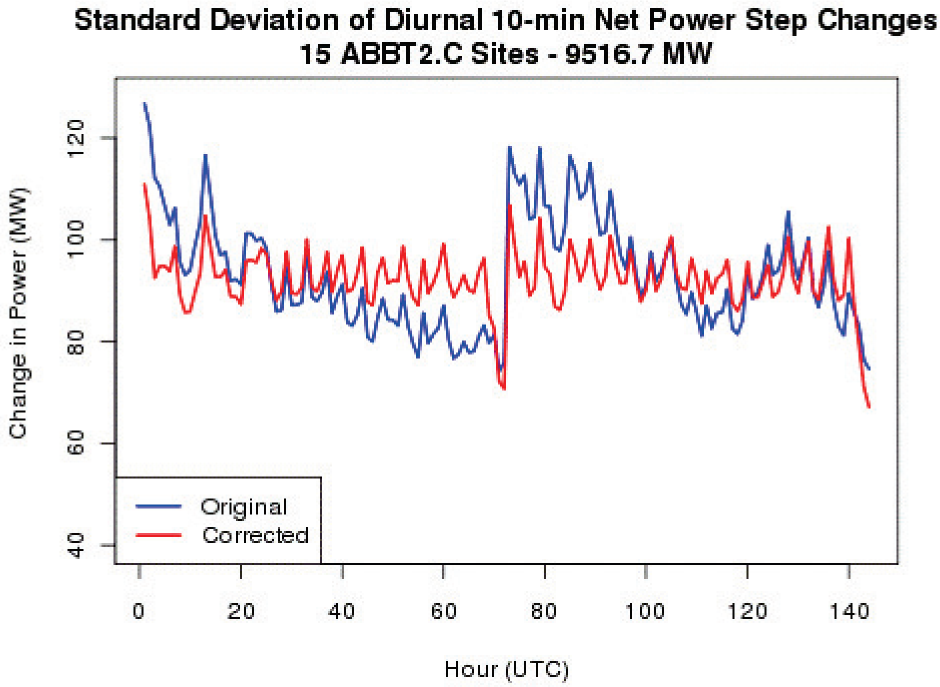


Figure 3-11. Diurnal mean standard deviation of 10-minute net power changes from 15 sites offshore California before (blue) and after (red) the aggregate diurnal correction

3.5 Analysis of Ramp Frequency Distributions

After the wind production profiles were simulated for each project site, the mean net power profiles as well as wind power ramps greater than 10-minute and 60-minute intervals were compared to onshore sites from EWITS. Data generated for ERGIS (an update to EWITS) were used in the comparison. Results for a single site in Michigan, a single site in North Carolina, an aggregate of sites in Michigan, and an aggregate of sites in Rhode Island are given in Figure 3-12 to Figure 3-15. Onshore and offshore sites were selected for their proximity and similarity in total nameplate capacity, but all sites were normalized to their nameplate capacity to better facilitate comparison. In nearly all cases, the offshore sites exhibited a higher mean CF and less variation between month and season compared to their onshore counterparts. The higher CF in the offshore data likely reflects both higher wind speeds in offshore areas as well as more aggressive power curves used in the current study. Although there was not much difference between the frequency distribution of 10-minute net power ramps onshore and offshore, offshore wind was somewhat more variable than onshore during a 60-minute interval. The only exception was the aggregate of several sites in Michigan, where the 10-minute offshore ramps were less variable than onshore, and both onshore and offshore variability was similar at 60-minute intervals.

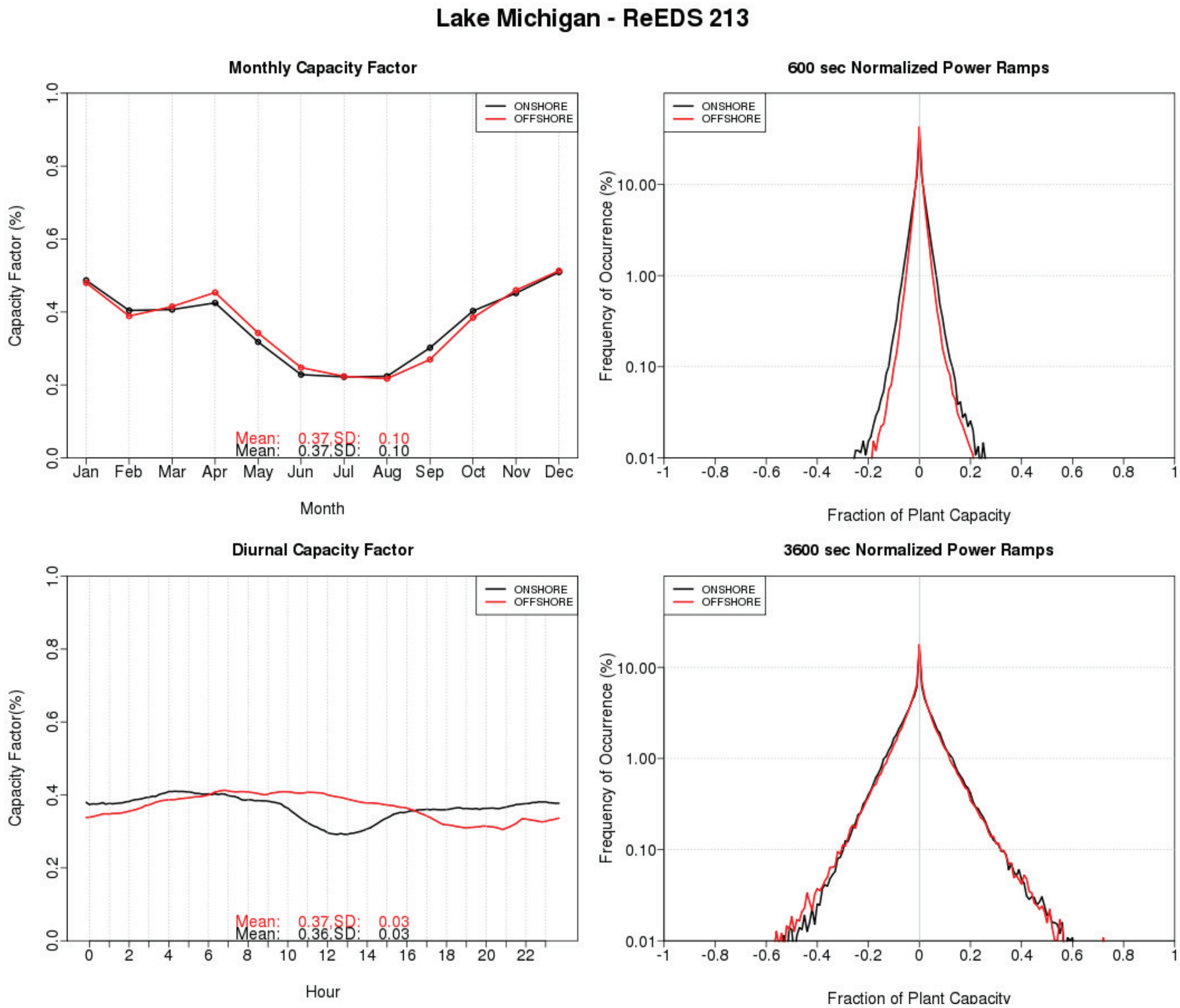


Figure 3-12. Comparison of onshore (black) and offshore (red) net power for a single site in Michigan normalized by nameplate capacity. Mean monthly and diurnal patterns are shown in the left panels; whereas 10-minute and 60-minute ramps in net power are shown in the right panels.

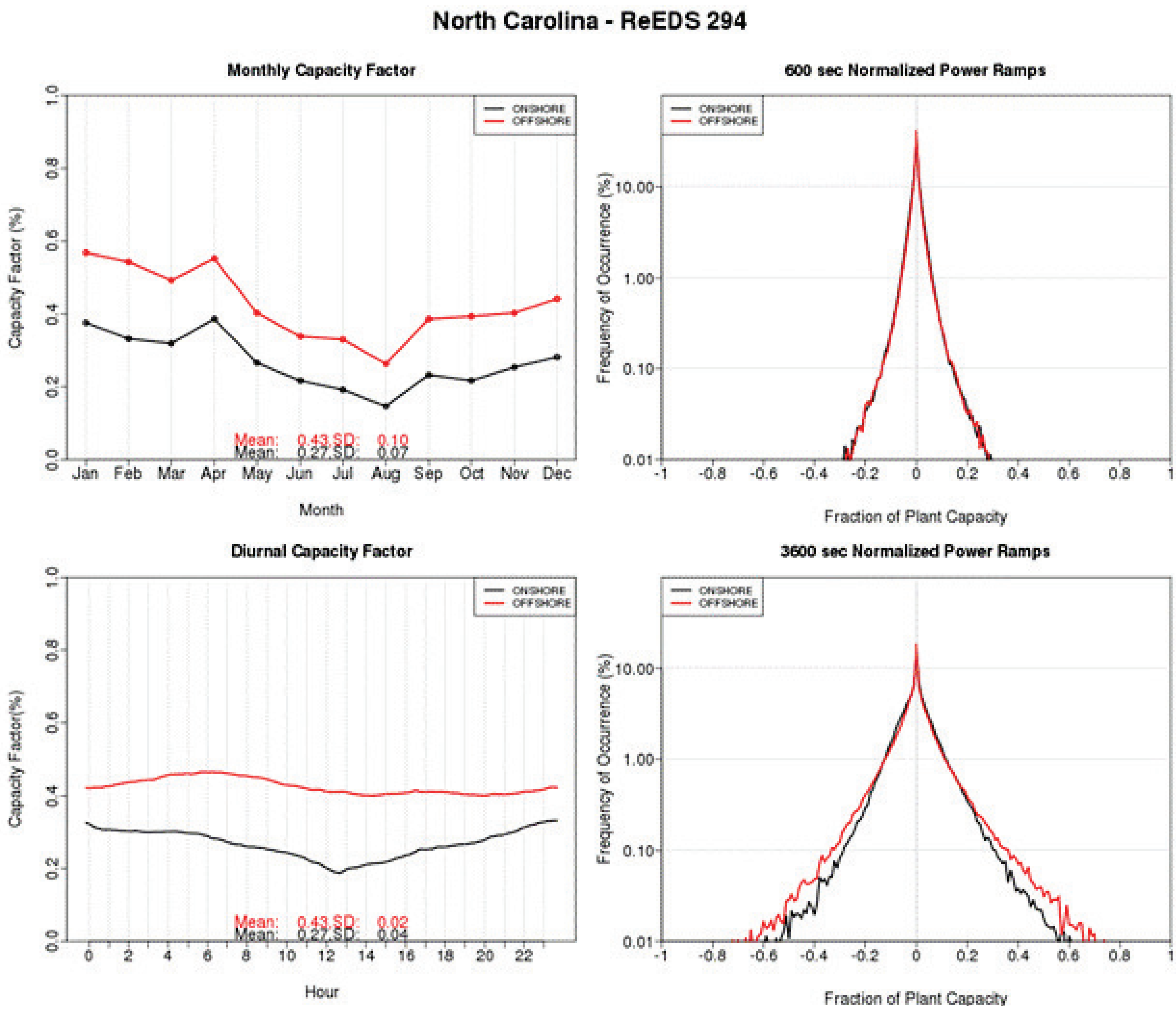


Figure 3-13. As in Figure 3-12, but for a single site in North Carolina

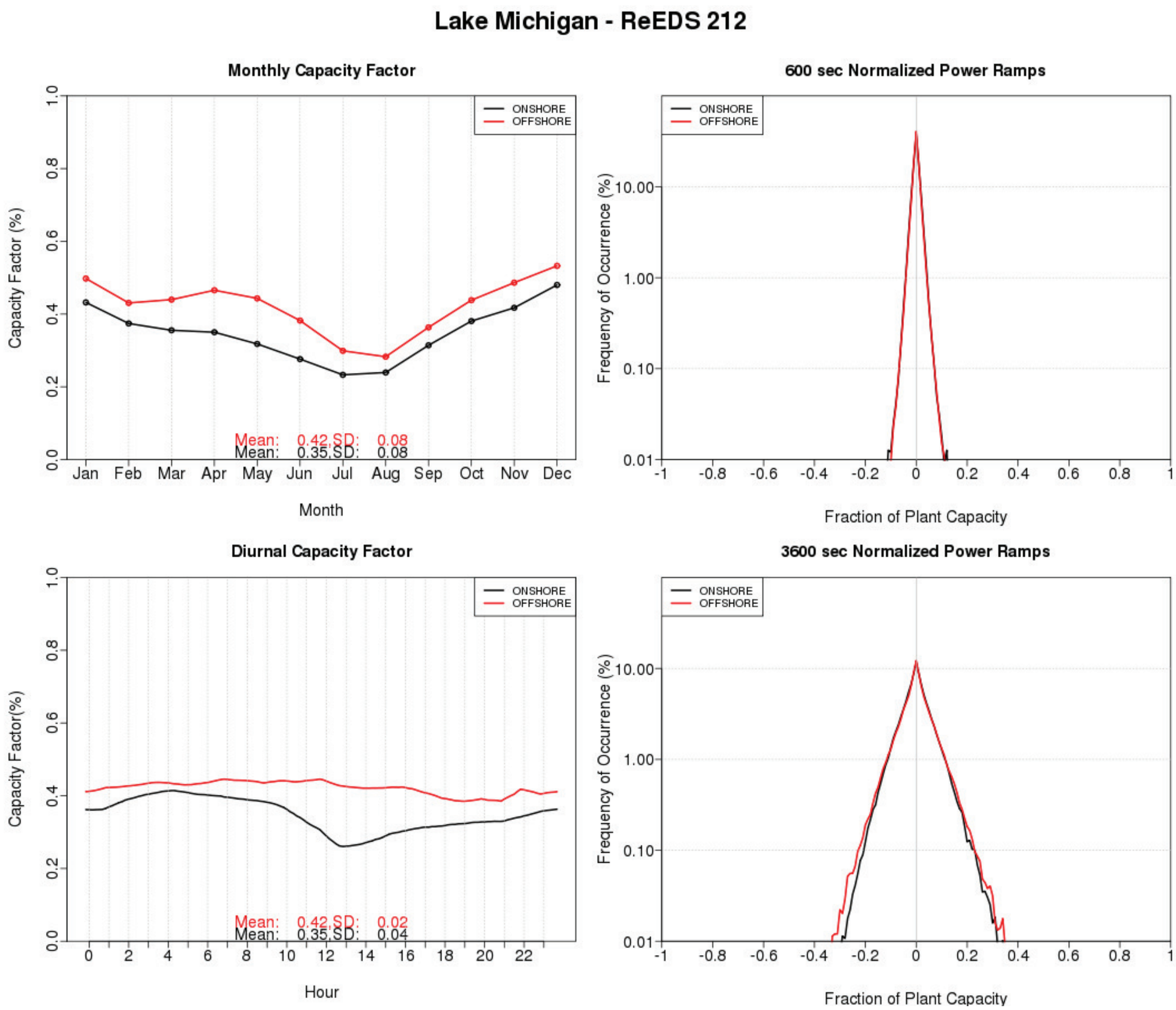


Figure 3-14. As in Figure 3-12, but for an aggregate of sites in Michigan

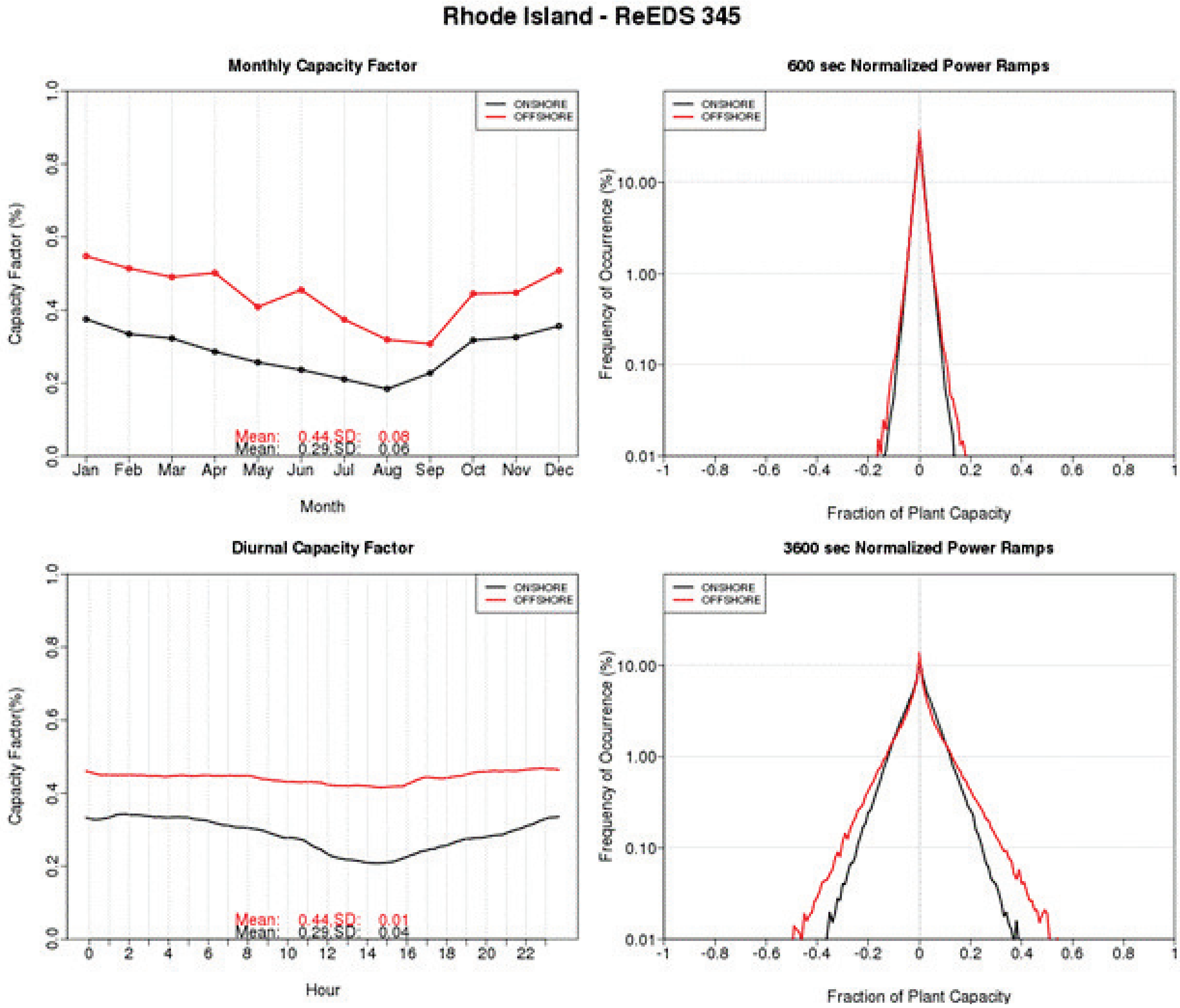


Figure 3-15. As in Figure 3-14, but for an aggregate of sites in Rhode Island

3.6 Conclusions

This study expanded upon EWITS to select likely locations for future offshore development along the Atlantic, Gulf, and Pacific coasts as well is within the Great Lakes. Planned and proposed wind farms as well as areas excluded from wind development were considered, and a GIS-based site selection was employed to site 209 offshore sites totaling 134+ GW. Wind and production profiles at 100 m were simulated at 10-minute intervals for the period from 2004 to 2006. Wind speeds were compared to measurements from elevated offshore monitoring platforms. Although there are uncertainties as a result of comparing modeled data at 100 m to measurements at 25 m to 50 m sheared to 100 m, the modeled data were found to represent observed patterns. A new adjustment was developed to correct for the impact of assimilating observations into the model, resulting in a smoother diurnal distribution of net power ramps. Results were presented to the TRC and found to be suitable for use in NOWEGIS.

3.7 Section References

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4.0 INITIAL INTEGRATION ANALYSIS

4.1 Introduction

The first task in the study was to determine the location and timing of the development of the 54 GW of offshore wind generation capacity as outlined in [1], using NREL's ReEDS model [2][3]. AWS Truepower performed more-refined site-determination analyses and ran a numerical weather prediction model to produce simulated wind power profiles for the years 2004, 2005, and 2006. These profiles complement the data set that was developed for EWITS [4][5]. An initial comparison of onshore and offshore profiles revealed that the latter typically presents higher mean CFs and less seasonal variation, but a higher variability of hourly ramps.

The objectives of this section of the study were to better understand the potential impacts of offshore wind energy on electric power systems and to determine if the typical analyses used for onshore wind are still pertinent and valid when applied to offshore wind—or if there are other refined or new analyses that are recommended. The impact of existing or projected onshore wind capacity was not included in this section, which focuses only on offshore wind.

A statistical analysis of offshore wind power variability and its effect on load profiles, including analysis of hourly and 10-minute wind data, was performed. Lessons from the analysis suggest that, from an operational point of view, the behavior of offshore wind and in its effect on the power system is very similar to that of onshore wind (barring the differences already highlighted). Thus, typical methodologies developed for the integration of onshore wind can still be utilized to integrate offshore wind. As an example, the increase in regulating reserve for the production cost simulations with wind is performed utilizing a method developed by NREL for onshore wind integration studies.

The statistical analysis was performed for seven electric power regions defined in GridView [6], which resemble existing RTOs and BAAs. Table 4-1 presents the regions studied and their corresponding installed offshore wind nameplate capacities. As summarized in [3], the East Coast regions—including PJM, New England, and the Carolinas—present high CFs with shallow depths; thus, the offshore wind deployment is concentrated there.

Table 4-1. Installed Offshore Capacity by GridView Region

Interconnection	GridView Region	Offshore Wind Capacity (GW)
Eastern	PJM	18.2
	New England	13.1
	Carolinas	8.3
	MISO	6.0
Western	Northern California	2.9
	NWPP	2.9
Texas	ERCOT	2.8

The remainder of the section is organized as follows: Section 2 presents the hourly and 10-minute statistical analysis of the offshore wind power profiles; Section 3 analyzes the impacts on load shapes and variability; Section 4 determines the impacts on regulating reserve requirements; and Section 5 summarizes the findings.

4.2 Wind Power Profile Analysis

The analysis began by examining the behavior of the offshore wind power profiles. Three years of data—2004, 2005, and 2006—are available at a 10-minute resolution. The production cost simulations utilize the 2006 profiles, so the analysis focused on that year, although comparisons to 2004 and 2005 are also provided to identify common trends and differences across years.

Three primary components comprised the effort: an analysis of power distributions, an analysis of hourly ramps, and an analysis of 10-minute ramps. A small, final section explores the relationships among wind power and ramps. In this report, a ramp is defined as the change in power output in between consecutive time steps (which can be 10 minutes or 60 minutes apart, depending on the section).

4.2.1 SUMMARY STATISTICS

This section summarizes the distributions of offshore wind power and ramps. Statistics include mean and standard deviation along with typical quantiles: minimum, first quartile (Q1), median, third quartile (Q3), and maximum. Table 4-2 contains the statistics for each region's power distribution for 2006. The regions are ordered according to deployed capacity. Statistics are shown in MW and as a percentage of installed capacity. Nearly all output ranges (from 0% to close to 100%) were observed across regions, and the variability was significant, as represented by the standard deviation and the interquartile ranges (from Q1 to Q3). Mean outputs (and the first and third quartiles) varied significantly from one region to another. The highest CFs were observed in the West—Northern California and the Northwest Power Pool (NWPP)—and exceeded 55%. The relatively small deployment in those areas allows only the very best sites to be selected and connected to the grid. It is also noteworthy that wind power in New England averaged 50%, with more than 13 GW of offshore wind generation installed. CFs for the remaining regions averaged 40%. Similar trends in average CFs were observed when data from 2006 was compared to data from 2004 and 2005 (Figure 4-1).

Table 4-2. Summary Statistics for Wind Power Distributions (MW and %) for 2006

Region	Capacity (GW)	Min.	Q1	Median	Q3	Max.	Mean	Std. Dev.
PJM	18.2	227	3,117	6,266	11,435	17,709	7,378	4,793
New England	13.1	30	3,062	6,518	10,132	12,923	6,559	3,833
Carolinas	8.3	0	1,030	2,375	4,676	7,994	2,997	2,294
MISO	6.0	30	1,172	2,134	3,450	5,776	2,383	1,464
NWPP	2.9	0	741	1,790	2,542	2,816	1,623	923
CA North	2.9	2	681	1,746	2,495	2,788	1,580	918
ERCOT	2.8	0	429	1,000	1,891	2,714	1,156	807
PJM	18.2	1.2%	17.1%	34.4%	62.8%	97.3%	40.5%	26.3%
New England	13.1	0.2%	23.3%	49.6%	77.1%	98.4%	49.9%	29.2%
Carolinas	8.3	0.0%	12.4%	28.7%	56.5%	96.5%	36.2%	27.7%
MISO	6.0	0.5%	19.4%	35.4%	57.2%	95.8%	39.5%	24.3%
NWPP	2.9	0.0%	25.9%	62.6%	88.9%	98.5%	56.8%	32.3%
CA North	2.9	0.1%	23.8%	61.1%	87.4%	97.6%	55.3%	32.1%
ERCOT	2.8	0.0%	15.6%	36.3%	68.6%	98.5%	42.0%	29.3%

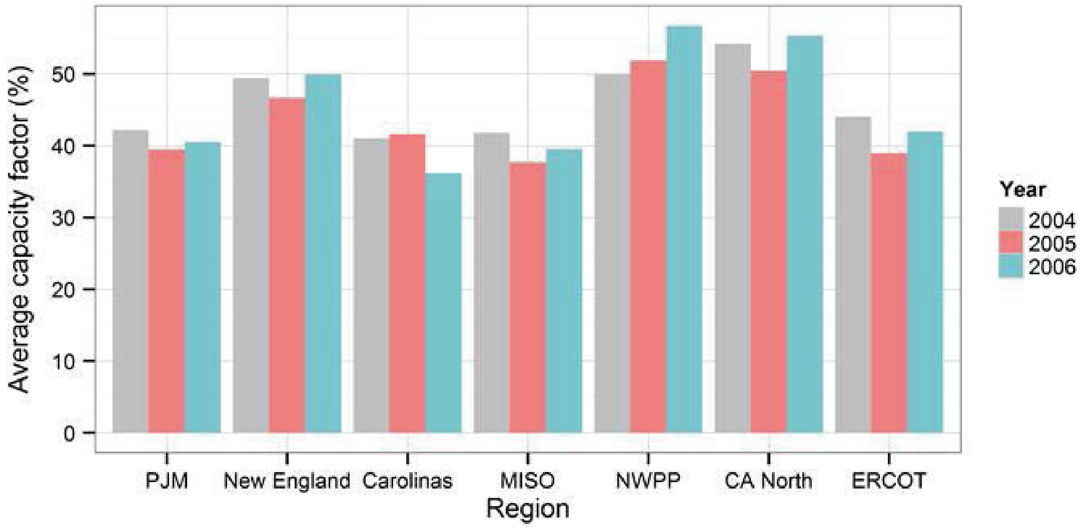

Figure 4-1. Average CFs by region and year

Hourly and 10-minute ramp statistics for 2006 are summarized in Table 4-3 and Table 4-4, respectively. Similar trends were observed for both. Ramps were centered on zero, and 50% of them were confined to a small range—from 2% to 3% of rated capacity for the hourly ramps and from 0.5% to 0.9% for the 10-minute ramps. Large regions, or those with more wind deployed, tended to have smaller variability relative to nameplate capacity (e.g., PJM and MISO), an effect of geographic diversity. Extreme values were significantly larger than those found in Q1 and Q3 for all regions, but especially for the Carolinas, NWPP, and the Electric Reliability Council of Texas (ERCOT).

Table 4-3. Summary Statistics for Hourly Ramp Distributions (MW and %) for 2006

Region	Capacity (GW)	Min.	Q1	Median	Q3	Max.	Mean	Std. Dev.
PJM	18.2	-4,760	-446	-3	438	5,557	1	875
New England	13.1	-4,001	-365	-4	345	4,239	-1	707
Carolinas	8.3	-2,601	-245	-5	240	3,497	0	524
MISO	6.0	-1,476	-153	-1	150	1,585	0	290
NWPP	2.9	-1,911	-92	-2	84	1,800	0	245
CA North	2.9	-1,179	-62	0	62	1,351	0	175
ERCOT	2.8	-1,040	-93	-1	90	1,440	0	197
PJM	18.2	-26.1%	-2.4%	0.0%	2.4%	30.5%	0.0%	4.8%
New England	13.1	-30.5%	-2.8%	0.0%	2.6%	32.3%	0.0%	5.4%
Carolinas	8.3	-31.4%	-3.0%	-0.1%	2.9%	42.2%	0.0%	6.3%
MISO	6.0	-24.5%	-2.5%	0.0%	2.5%	26.3%	0.0%	4.8%
NWPP	2.9	-66.8%	-3.2%	-0.1%	2.9%	62.9%	0.0%	8.6%
CA North	2.9	-41.3%	-2.2%	0.0%	2.2%	47.3%	0.0%	6.1%
ERCOT	2.8	-37.7%	-3.4%	0.0%	3.3%	52.3%	0.0%	7.1%

Table 4-4. Summary Statistics for 10-Minute Ramp Distributions (MW and %) for 2006

Region	Capacity (GW)	Min.	Q1	Median	Q3	Max.	Mean	Std. Dev.
PJM	18.2	-1,638	-100	0	99	1,503	0	201
New England	13.1	-1,347	-78	0	76	1,105	0	157
Carolinas	8.3	-1,036	-56	0	55	1,190	0	130
MISO	6.0	-447	-35	0	34	612	0	68
NWPP	2.9	-925	-21	0	20	871	0	59
CA North	2.9	-556	-17	0	17	546	0	43
ERCOT	2.8	-785	-24	0	24	846	0	62
PJM	18.2	-9.0%	-0.5%	0.0%	0.5%	8.3%	0.0%	1.1%
New England	13.1	-10.3%	-0.6%	0.0%	0.6%	8.4%	0.0%	1.2%
Carolinas	8.3	-12.5%	-0.7%	0.0%	0.7%	14.4%	0.0%	1.6%
MISO	6.0	-7.4%	-0.6%	0.0%	0.6%	10.2%	0.0%	1.1%
NWPP	2.9	-32.3%	-0.7%	0.0%	0.7%	30.5%	0.0%	2.1%
CA North	2.9	-19.5%	-0.6%	0.0%	0.6%	19.1%	0.0%	1.5%
ERCOT	2.8	-28.5%	-0.9%	0.0%	0.9%	30.7%	0.0%	2.3%

4.2.2 OFFSHORE WIND POWER DISTRIBUTION

After being summarized through statistics, the distributions were further examined to understand the behavior of the wind power profiles throughout the year. Figure 4-2 represents the distributions of wind power by region for all three years of data. As previously observed, wind power consistently ranged from zero to nameplate capacity. The central portions of the distributions were consistent across years and rather wide. There was not a single year in which the power output was the highest for all regions.

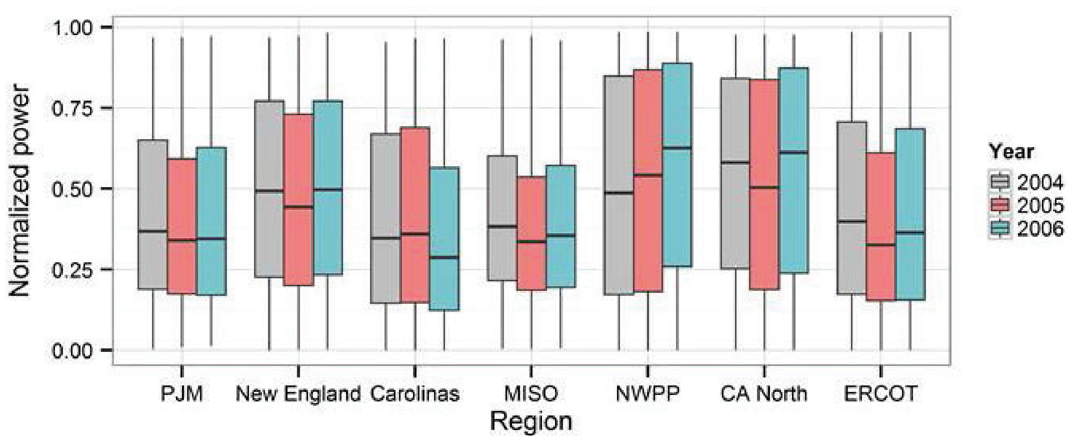

Figure 4-2. Boxplots showing normalized wind power by region and year

The boxplots in Figure 4-3 show power distributions by month. Regions are presented in rows. The left column contains 2006 data only; whereas the right column contains data from 2004, 2005, and 2006 pooled together. Wind power in the western regions tended to be highest during the summer months—especially for Northern California, which showed a very narrow distribution in July. The exact opposite happened in the eastern regions, the Great Lakes, and ERCOT, where power was usually lower during July and August. The trends observed for 2006 were generally consistent with the trends observed for all three years.

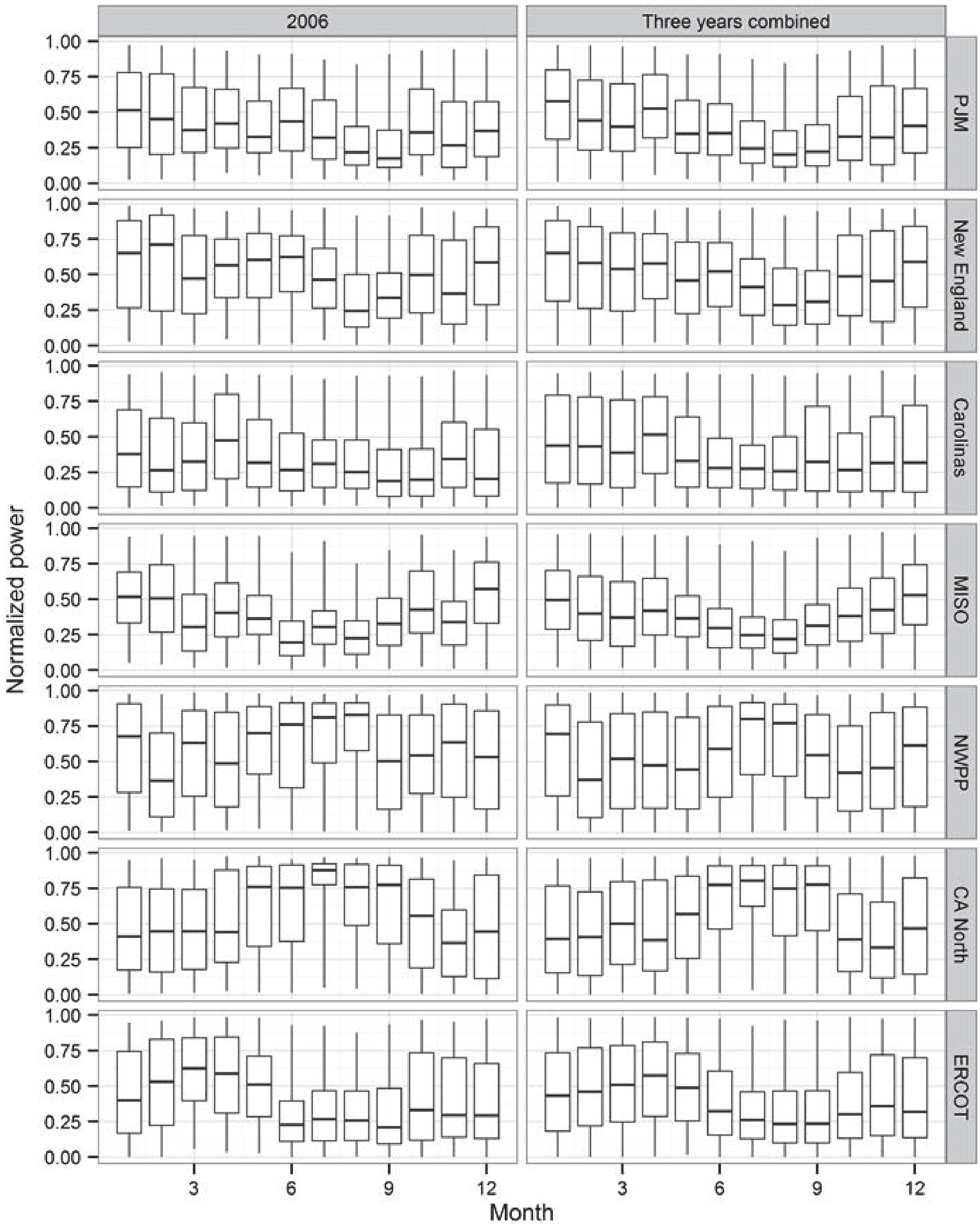

Figure 4-3. Boxplots showing normalized power by month and region for 2006 and the three years combined

The boxplots in Figure 4-4 show wind power by hour of day for one month per season (January, April, July, and October). These plots show that in July, power outputs greater than 75% in Northern California and 50% in NWPP were common. July was also an interesting month for the Carolinas, PJM, and New England, where power output was lower. In those regions, there was a dip in power output early in the day, followed by an in increase in the afternoon, most likely due to sea breezes. This phenomenon was also present to a smaller degree during April and October. In general, power output appeared to be higher during nighttime hours for most combinations of regions and months.

Figure 4-5 compares average power by hour of day and region to the same selected months for all three years. Very similar trends were observed in most cases. The most notable exceptions for 2006 (when compared to 2004 and 2005) were the largest power output during October afternoons for NWPP and the higher mean output during July for PJM and Northern California, although these changes were only moderate.

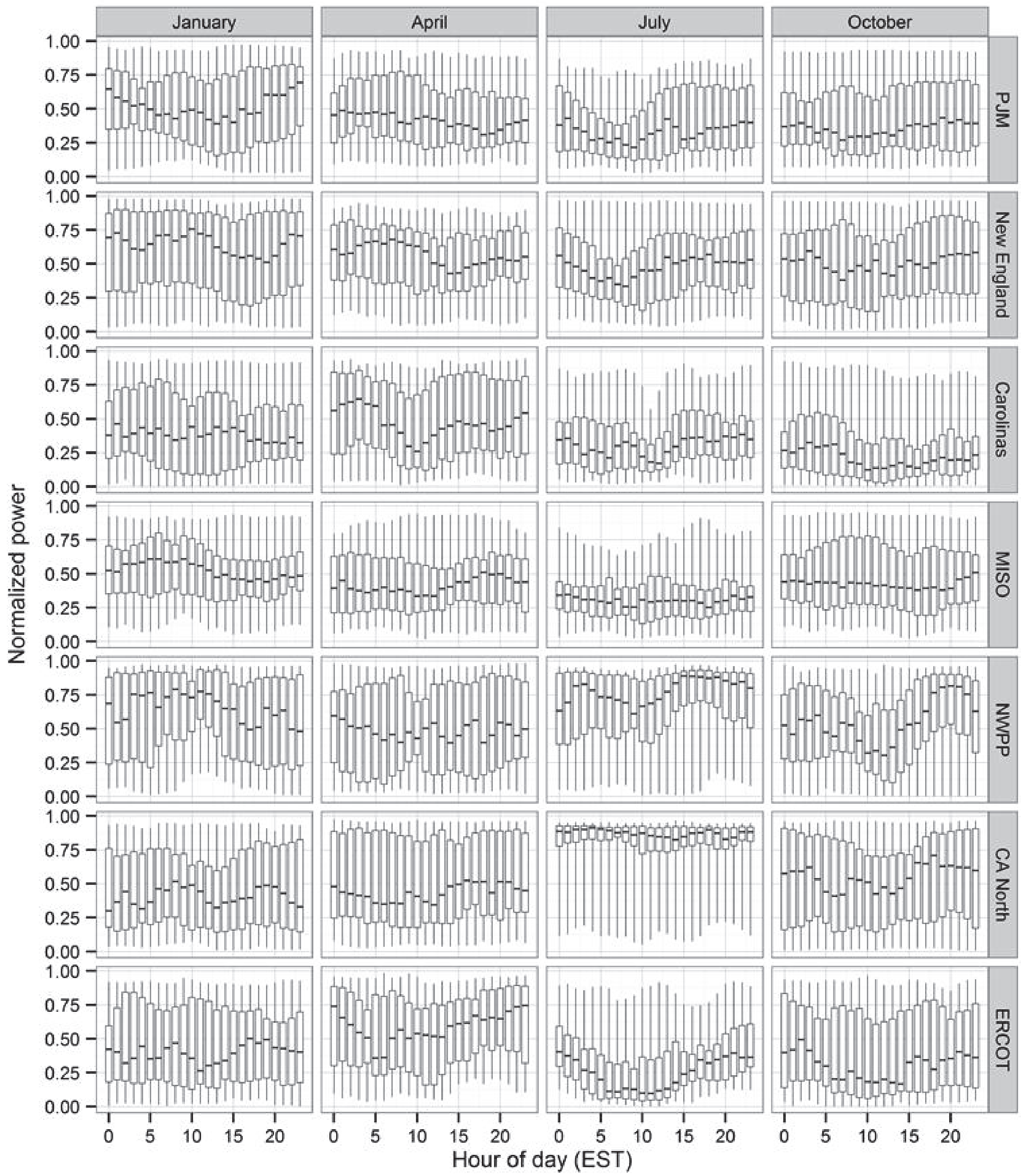

Figure 4-4. Boxplots showing normalized wind power by hour of day and region for selected months in 2006

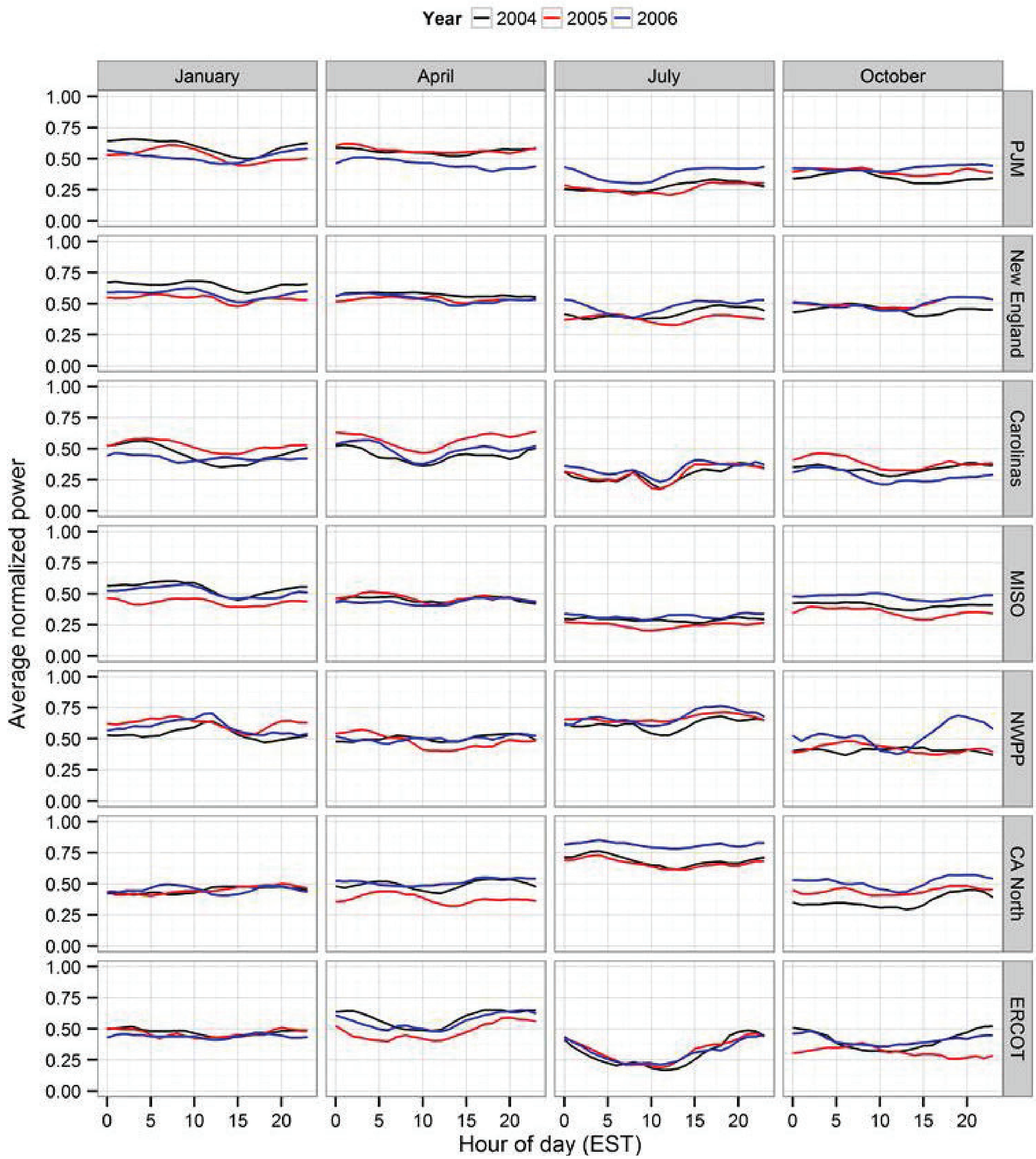

Figure 4-5. Average normalized wind power by hour of day and region for all three years

Contour plots are another vehicle to show the wind power dependency on month and time of day. Figure 4-6 clearly shows the extremely high output in the western regions during July. The remaining regions presented their lowest average outputs during the summer and tended to peak during spring nights. The plots also show the power decreases during summer mornings and pickups during summer afternoons in the Carolinas, ERCOT, and PJM.

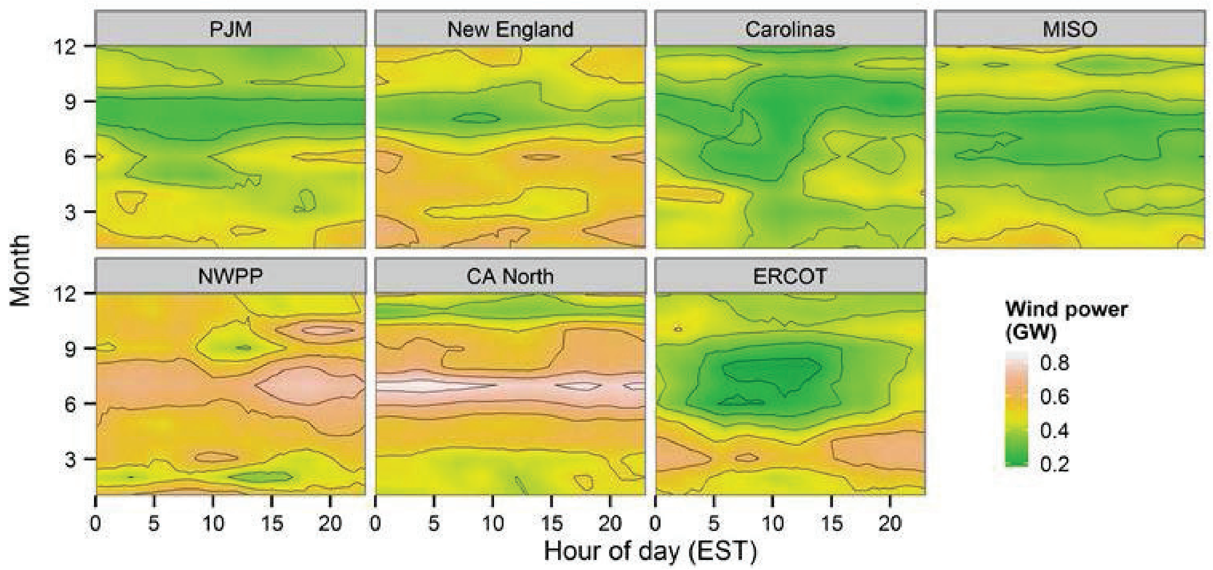

Figure 4-6. Contour plots showing average wind power by month and hour of day

4.2.3 HOURLY OFFSHORE WIND VARIABILITY

The study of hourly ramps contributes to the understanding of how offshore wind could affect the load-following capabilities of a system. Hourly (and multi-hourly) ramps could affect the net load and require a change in how conventional generators are typically committed and cycled.

Figure 4-7 and Figure 4-8 compare the hourly ramps for 2006 to 2004 and 2005. The boxplots in Figure 4-7 indicate that the central portion of the variability remained rather consistent from one year to another, although the interquartile distance was marginally bigger in some regions for 2004. Extreme values were much larger and changed from year to year. In particular, 2006 presented some of the largest values for the three years studied, especially in NWPP. Figure 4-8 represents ramp distributions, which remained largely unchanged from year to year. The vast majority of the hours presented ramps smaller than 20% of the installed capacity for all regions and years, and half of them were smaller than 3%.

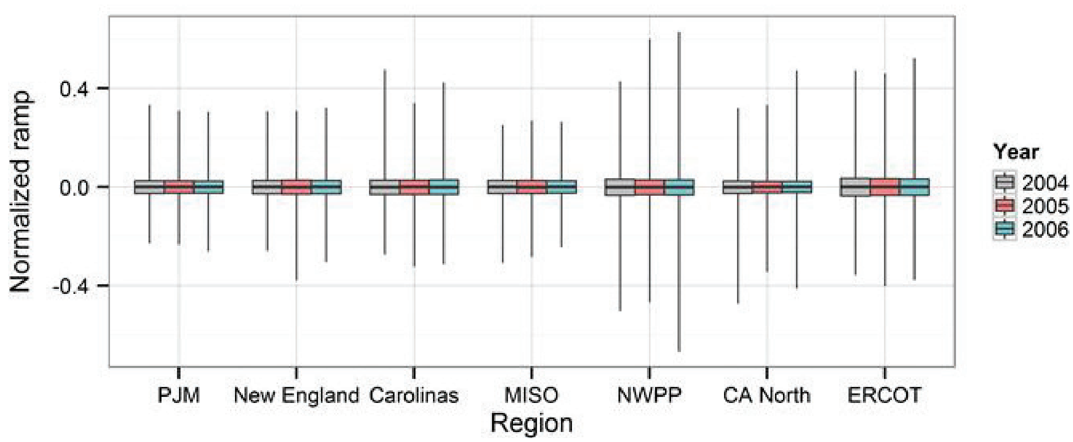

Figure 4-7. Boxplots showing hourly ramps by region and year

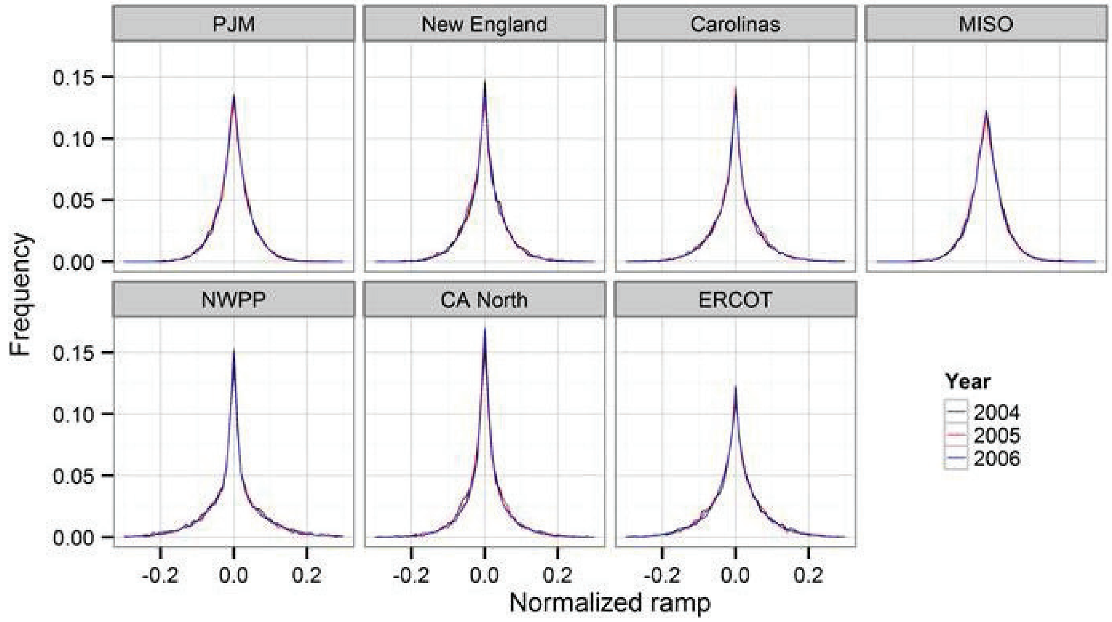

Figure 4-8. Normalized hourly ramp distributions for all three years

Ramp distributions changed from one region to another, as shown in Figure 4-9. Alternatively, Figure 4-10 shows the central portion of the hourly ramp duration curves, normalized to installed capacity. In the western regions (Northern California and NWPP), there is a high concentration of ramps close to zero, mainly because the shapes in these regions tended to be very consistent during the summer months. However, extreme ramps are more frequent in NWPP, but not in Northern California. On the other hand, the eastern regions with smaller amounts of wind capacity (ERCOT and MISO) tended to have the least number of ramps close to zero; whereas their tails behaved differently. Extreme ramps were rare in MISO and much more common in ERCOT.

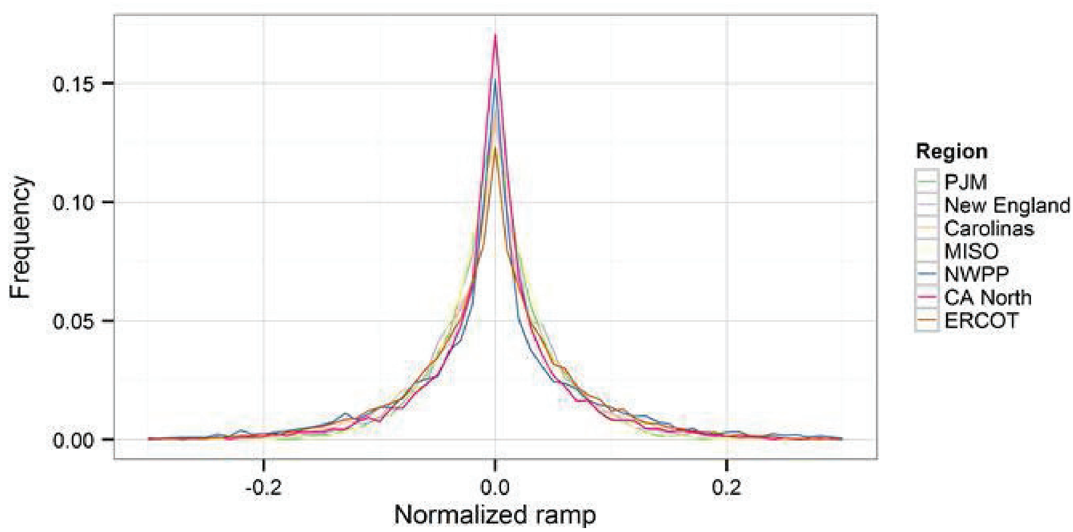

Figure 4-9. Normalized hourly ramp distributions by region for 2006

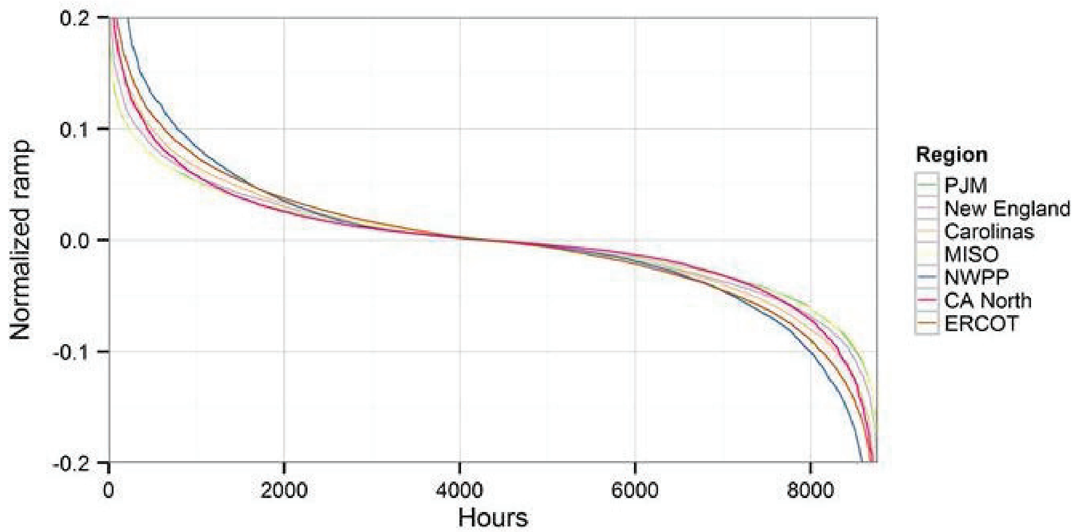

Figure 4-10. Normalized hourly ramp duration curves for 2006

Similar conclusions were extracted when the distributions were broken down by month. Figure 4-11 shows how seasonal effects vary from region to region. For instance, PJM, NWPP, and ERCOT showed similar distributions for all four selected months; April was more variable in New England; July was more variable in the Carolinas; October was the least variable in MISO; and January was the most variable in Northern California. These trends are also observed in the boxplots in Figure 4-12, which show variability by hour of day for selected months. The graph shows that there were typical positive and negative trends throughout the day during several months and in several regions—for example, the Carolinas during April and July.

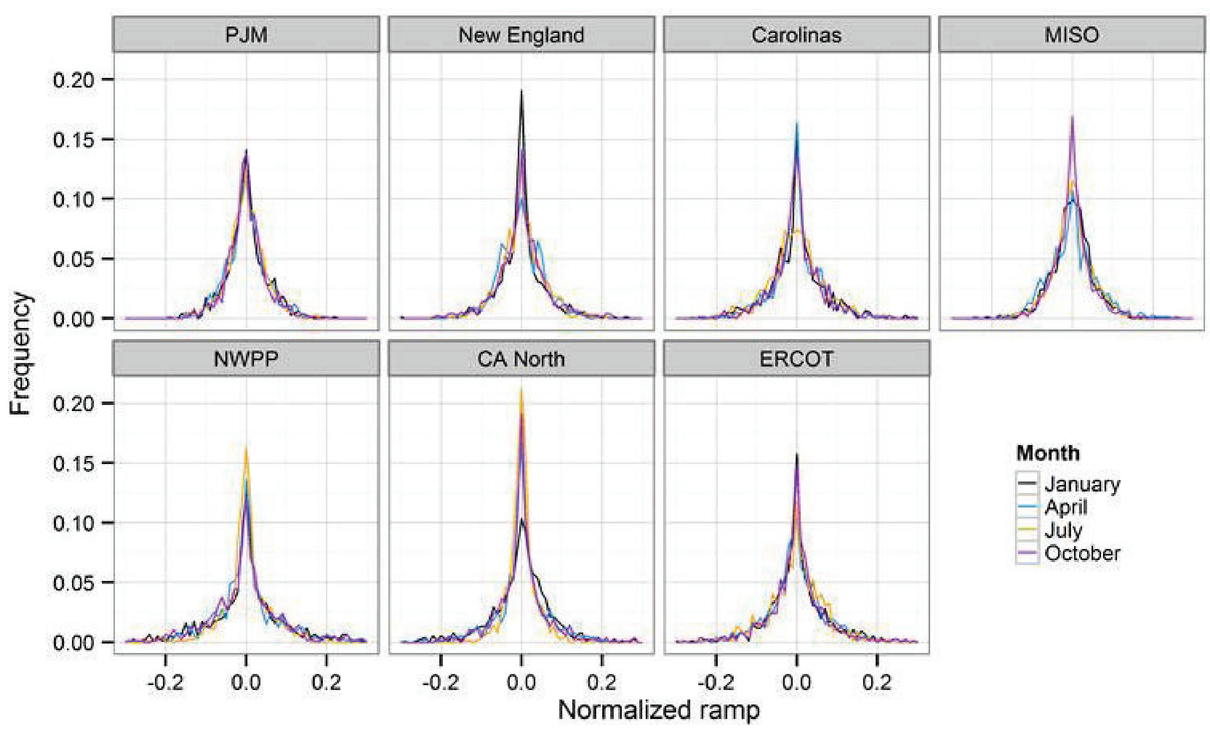

Figure 4-11. Normalized hourly ramp distributions for selected months in 2006

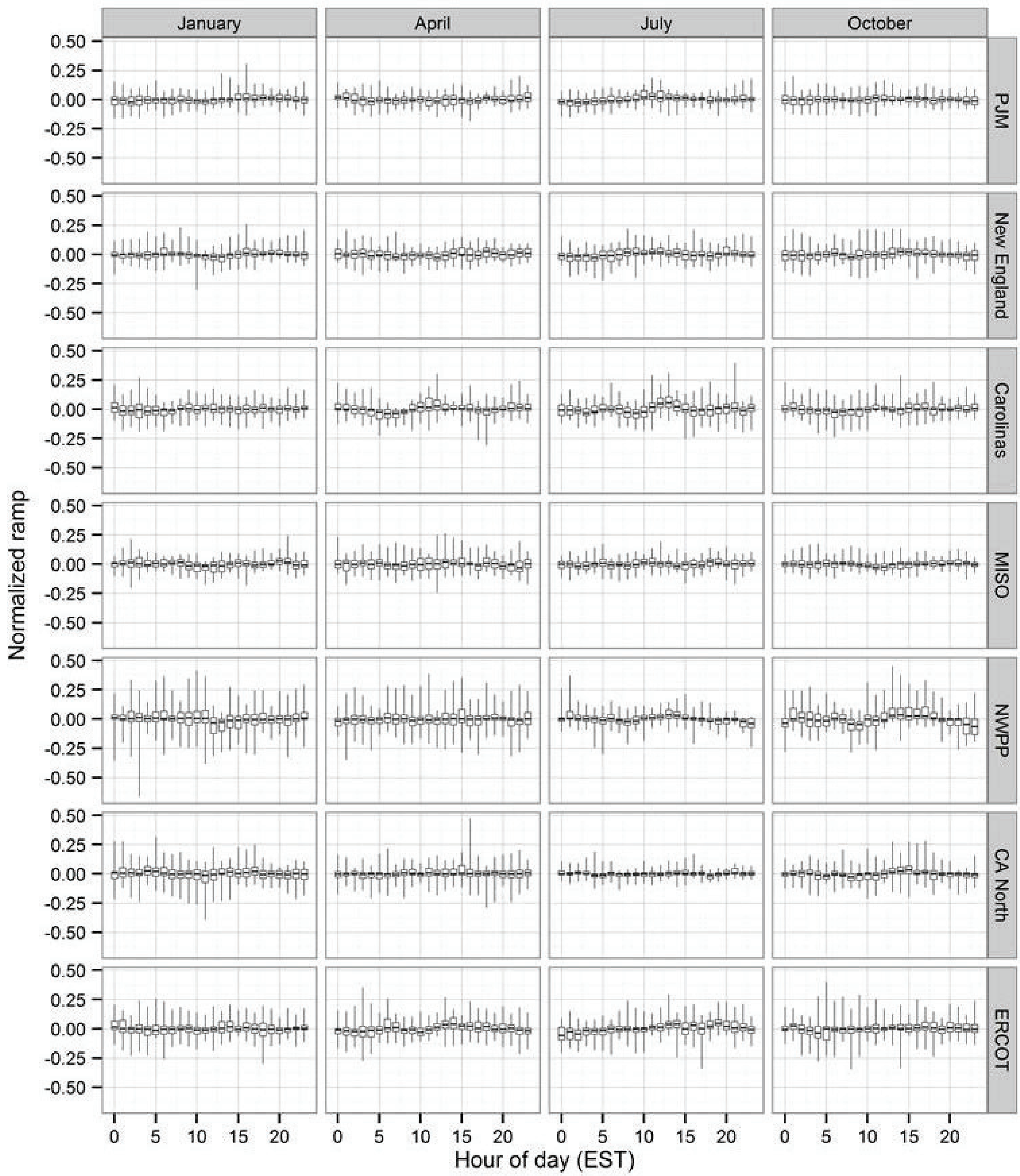

Figure 4-12. Boxplots showing normalized hourly ramps by region and hour of day for selected months in 2006

The contour plots showing average ramps in Figure 4-13 represent an alternative visualization of daily and monthly trends. The Carolinas and ERCOT presented several months in which there were average decreases in power during the morning (and thus a negative ramp) followed by positive ramps during the afternoon. These trends were also present to a smaller degree in NWPP and PJM.

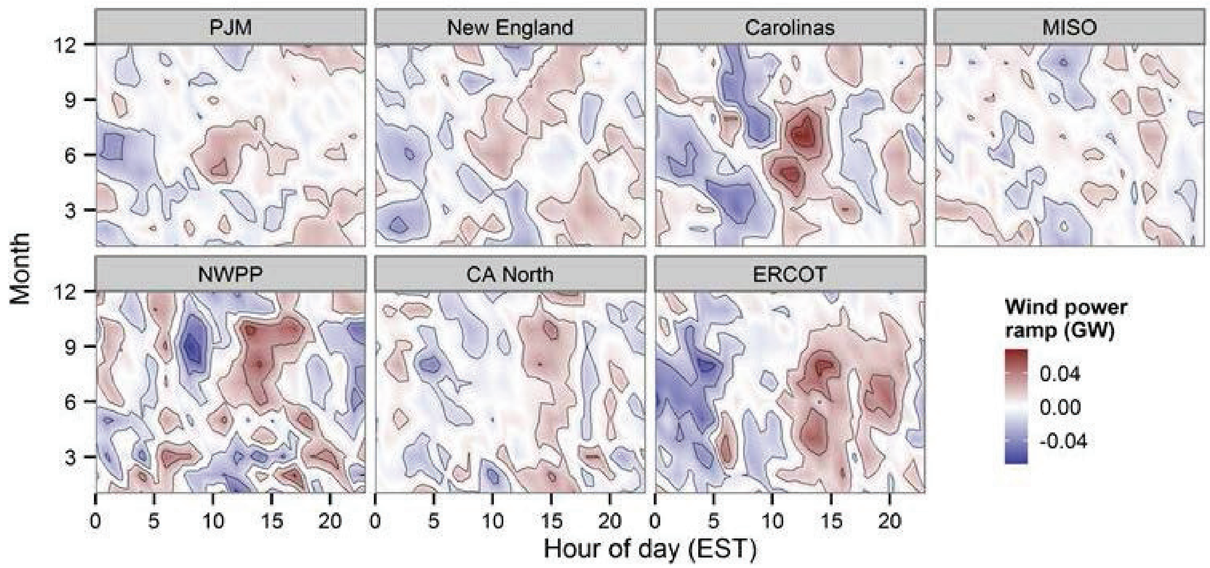

Figure 4-13. Contour plots showing average hourly ramps by month and hour of day

4.2.4 TEN-MINUTE OFFSHORE WIND VARIABILITY

Hourly wind ramps can affect the load-following capabilities of the electric power system; whereas sub-hourly variability can impact system regulations. This section studies 10-minute ramps.

Figure 4-14 compares 10-minute distributions for each region for the three years of data. Distributions were tightly concentrated around zero and were similar throughout multiple years, although the interquartile distances were slightly larger for 2004. Extreme values ranged from 10% to 35% of nameplate capacity. A closer look at the central portion of the distributions (Figure 4-15) revealed that they were virtually indistinguishable across years. The vast majority of the ramps were smaller than 3% of nameplate capacity, and more than half were smaller than 1%.

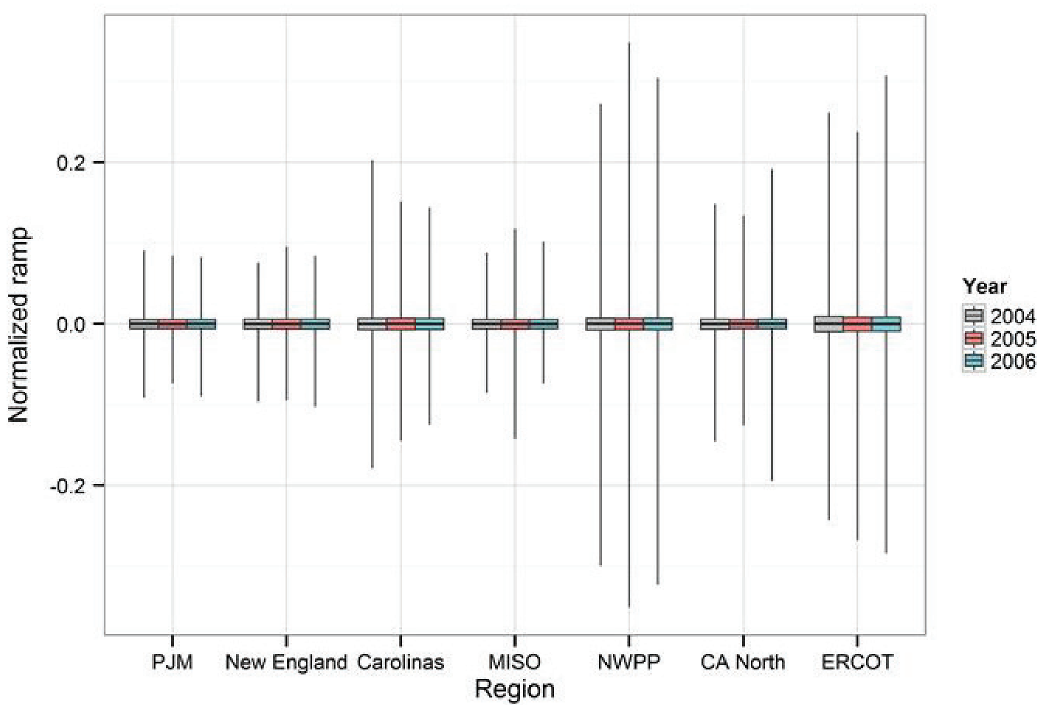

Figure 4-14. Boxplots showing 10-minute ramps by region and year

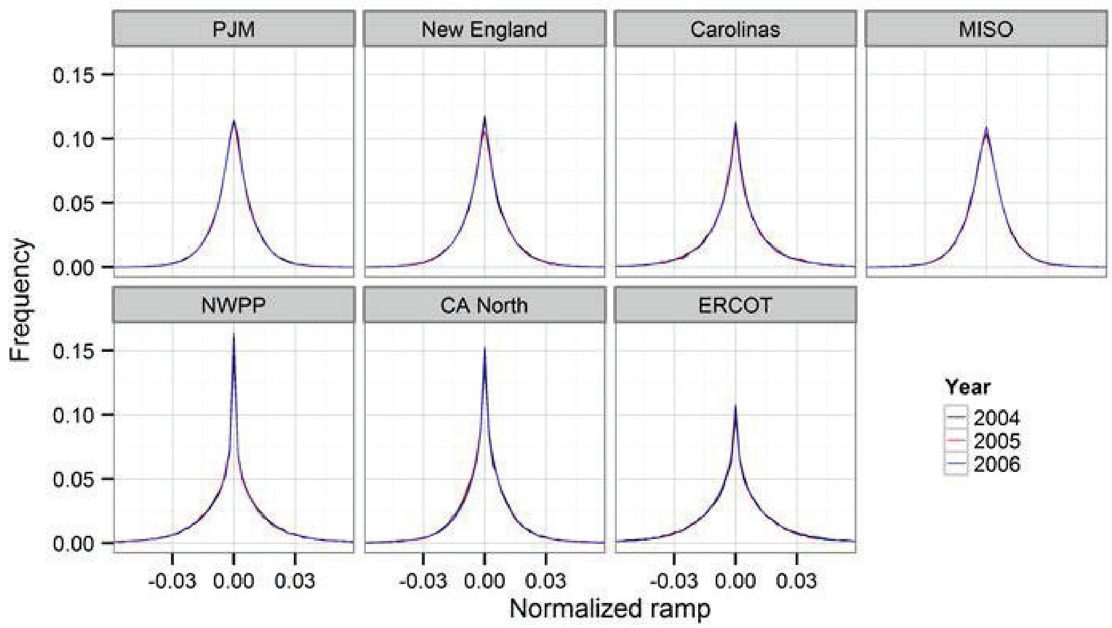

Figure 4-15. Normalized ramp distributions for all three years

A side-by-side comparison of regional 10-minute ramp distributions (Figure 4-16) and duration curves (Figure 4-17) reveals that Northern California and NWPP behaved differently compared to the remaining regions. The western regions presented a higher concentration around zero, mainly because of the consistently high wind power output, resulting in less variability during the summer months (Figure 4-18). As was the case with hourly ramps, the behavior of the tails was very different in the two regions, and they were more pronounced in NWPP. The distributions in the remaining regions were closer together. Seasonal effects were more pronounced for the 10-minute ramps, and April and July typically had the largest variability.

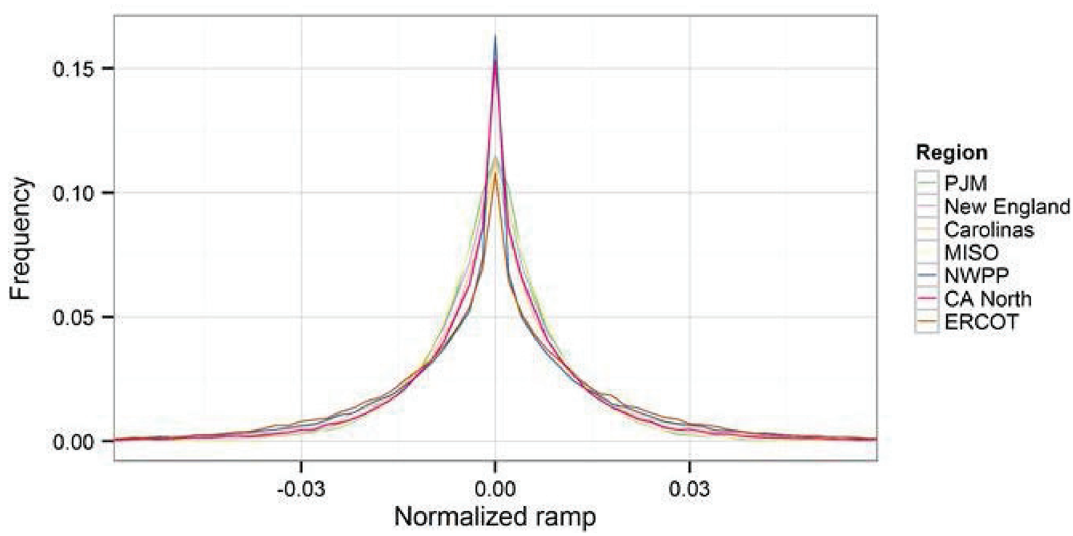

Figure 4-16. Normalized 10-minute ramp distributions by region for 2006

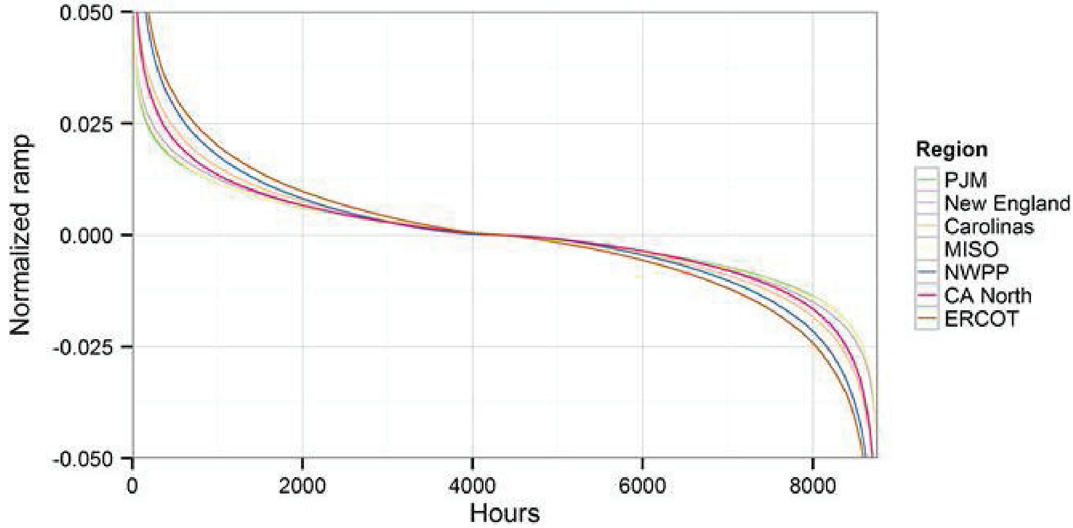

Figure 4-17. Normalized 10-minute ramp duration curves for 2006

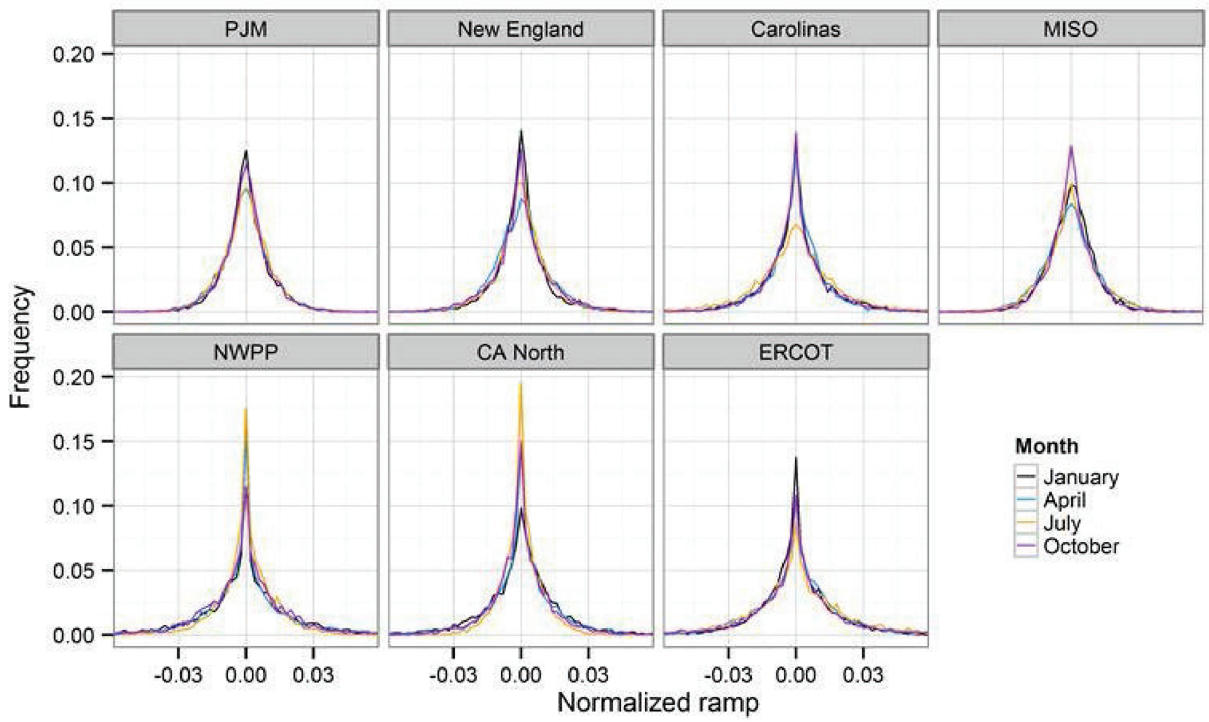

Figure 4-18. Normalized 10-minute ramp distributions for selected months in 2006

Similar conclusions can be extracted from the boxplots shown in Figure 4-19; that is, there were larger ramps during April and July for the eastern regions and during January and April for the western regions. Daily trends were much weaker when compared to the hourly ramps. Distributions were generally centered on zero. The Carolinas during July and NWPP during October were the most distinguishable exceptions, with slightly negative ramps during the mornings and positive ramps during the afternoons.

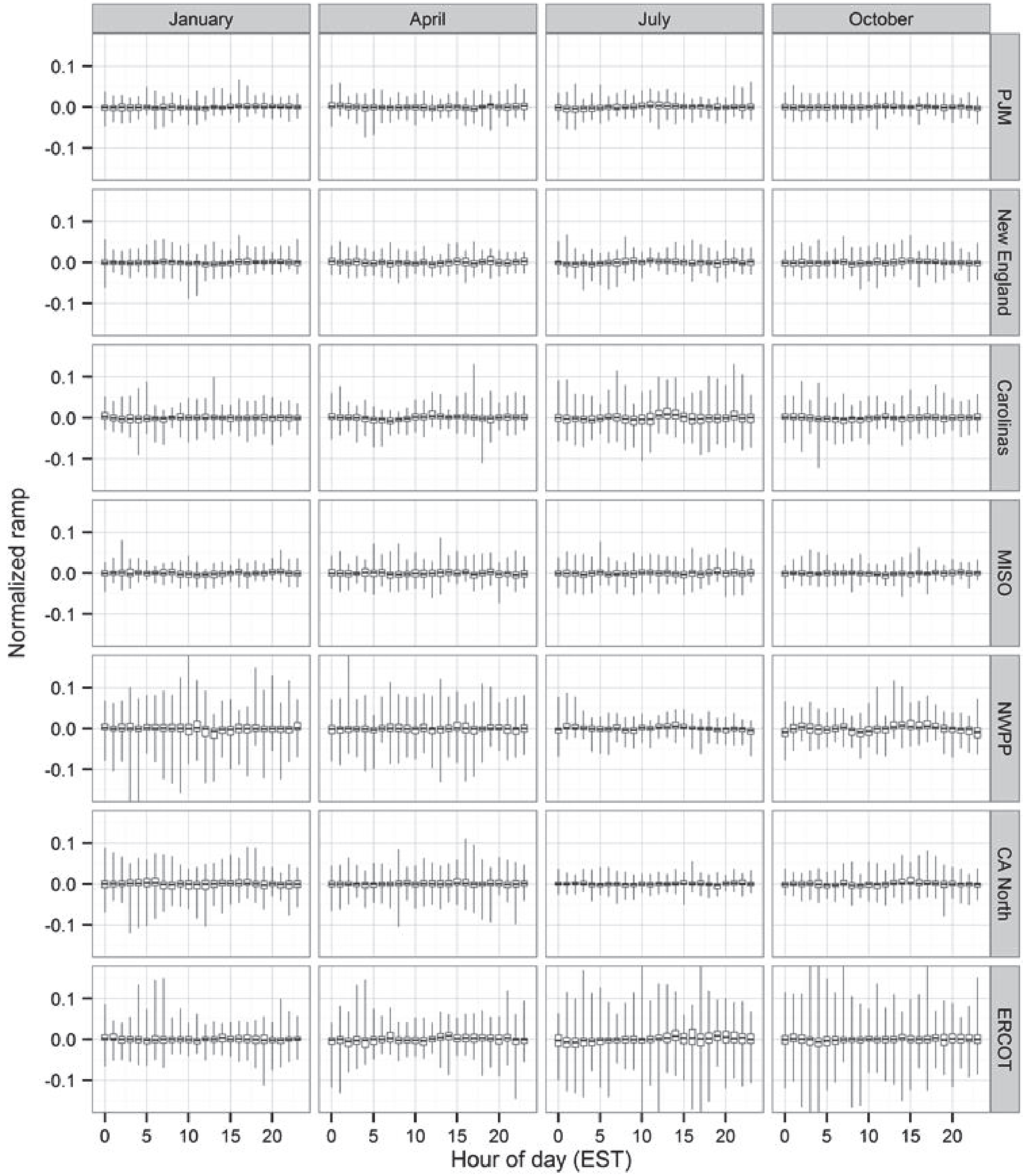

Figure 4-19. Boxplots showing normalized wind ramps by hour of day and region for selected months in 2006

4.2.5 OFFSHORE WIND VARIABILITY AND POWER

Past integration studies [5][7] observed very specific relationships among the power output at any given moment and the immediate following ramp for onshore wind power. The same relationships were observed in this study for hourly (Figure 4-20) and 10-minute ramps (Figure 4-21) for the seven regions with offshore wind.

The plots reveal that wind variability was largest when power output was close to 50%, and it gradually decreased toward the extremes. The main driver for this behavior is represented by the shape of the wind power curves (the curves that show the conversion from wind speed to wind power), which are usually steepest in the middle. Thus, small changes in wind speed in that region correspond to large changes in power output; whereas power changes were relatively smaller in the extremes. This behavior is one of the factors driving the design of reserve calculations for wind that are discussed in a later section.

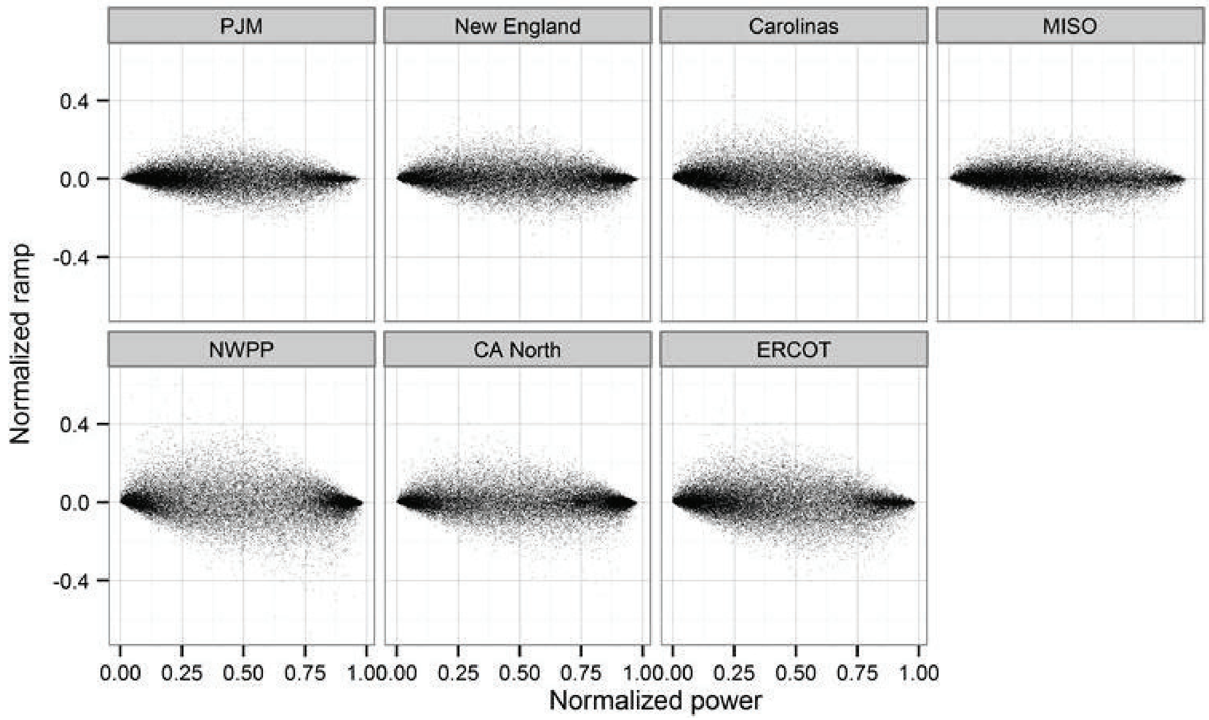

Figure 4-20. Hourly normalized ramps versus normalized power

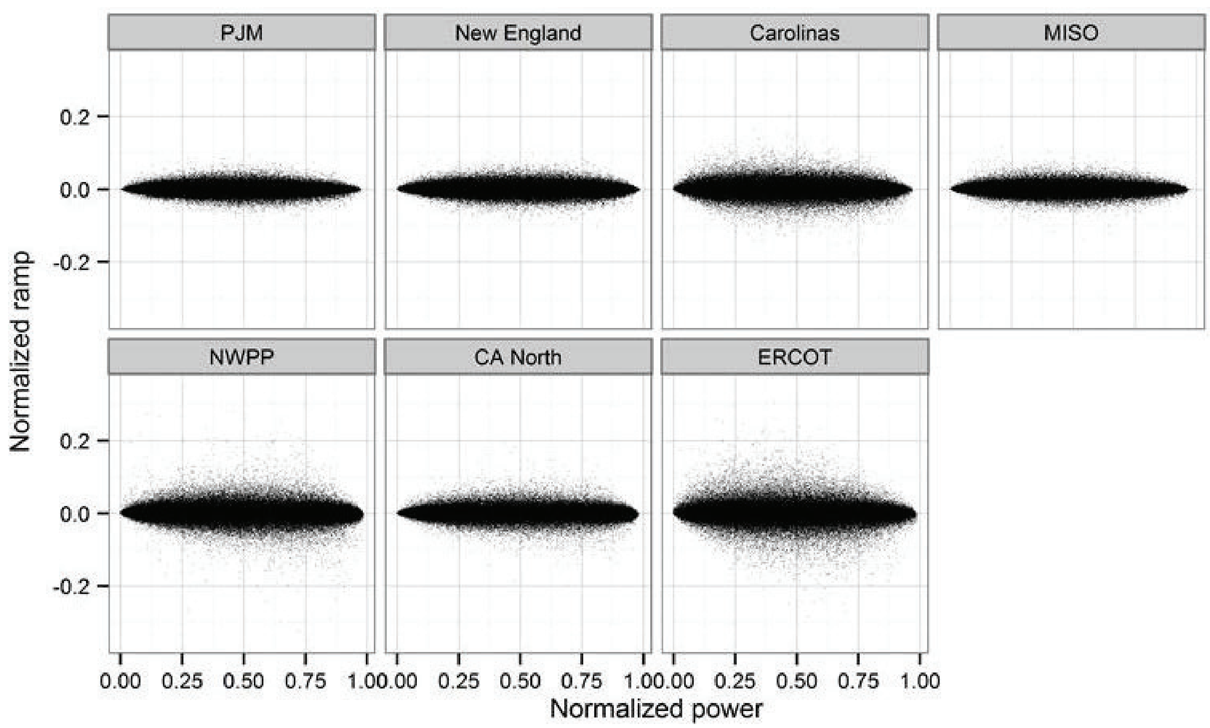

Figure 4-21. Ten-minute normalized ramps versus normalized power

4.3 Load and Net Load Analysis

The previous section studied the behavior of wind power, including its variability and seasonal and daily dependencies. This section focuses on its relationship to load. In typical system operations, and given that wind has an operating cost close to zero, it tends to be dispatched first. The remaining generator fleet is then used to match the net load (i.e., load minus wind generation). The analysis of net load focused on the 54 GW of offshore wind capacity in this study and excluded the contribution of any other existing variable renewable generators (e.g., land-based wind or solar photovoltaic).

This section compares the effects of adding offshore wind to the electric power system using 2006 load and wind power profiles. The analysis was limited to hourly (not sub-hourly) variability, given that that was the only time-step resolution used in the production cost simulations.

4.3.1 SUMMARY STATISTICS

Table 4-5 and Table 4-6 summarize the statistics for the hourly load and net load power and ramp distributions, respectively. Regions are organized according to installed nameplate capacity. The largest impacts across all statistics were found for New England. This is the only region that presented negative net load values—i.e., there were times when offshore wind power was larger than load. In those instances, wind power needs to be curtailed, exported to neighboring regions, or a combination of the two.

Other regions presented a larger ratio of load to installed wind capacity (Table 4-7), and the differences between load and net load were moderate. In general, the change in the minima and Q1 were larger than the changes in the upper portion of the power distributions. With the exception of New England, the largest changes in ramps were observed for the extreme values. The following sections study these changes in more detail.

Table 4-5. Summary Statistics for Load and Net Load Power Distributions (MW)

Region	Data	Min.	Q1	Median	Q3	Max.	Mean	Std. Dev.
PJM	Load	67,939	96,010	108,883	118,276	184,269	108,874	18,159
	Net Load	55,801	88,062	100,979	111,859	177,960	101,520	19,000
New England	Load	10,418	14,510	17,359	19,107	31,633	17,083	3,366
	Net Load	-1,322	6,794	10,420	14,388	26,497	10,529	5,053
Carolinas	Load	17,302	23,346	25,952	29,648	47,837	27,090	5,561
	Net Load	17,302	23,346	25,952	29,648	47,837	27,090	5,561
MISO	Load	37,414	49,094	55,698	61,488	97,130	56,284	9,412
	Net Load	32,801	46,783	53,165	59,120	94,628	53,906	9,586
NWPP	Load	13,891	18,570	20,836	23,059	32,668	20,899	3,312
	Net Load	11,831	16,826	19,220	21,495	31,778	19,282	3,461
CA North	Load	8,793	13,135	16,110	17,323	28,981	15,667	3,166
	Net Load	6,410	11,621	14,337	16,109	26,412	14,089	3,120
ERCOT	Load	26,352	36,165	40,476	49,031	78,423	43,388	10,757
	Net Load	24,482	34,831	39,339	47,819	78,024	42,226	10,884

Table 4-6. Summary Statistics for Hourly Load and Net Load Ramp Distributions (MW)

Region	Data	Min.	Q1	Median	Q3	Max.	Mean	Std. Dev.
PJM	Load	-12,617	-2,437	-253	2,495	13,609	0	4,248
	Net Load	-14,008	-2,571	-232	2,572	16,682	0	4,358
New England	Load	-2,833	-487	-50	430	3,315	0	903
	Net Load	-4,922	-694	-28	701	4,671	1	1,145
Carolinas	Load	-3,836	-836	-85	807	4,460	0	1,298
	Net Load	-5,796	-898	-88	859	4,989	-2	1,399
MISO	Load	-8,202	-1,340	-148	1,221	7,789	0	2,344
	Net Load	-7,813	-1,354	-141	1,238	7,939	0	2,359
NWPP	Load	-2,679	-562	-85	462	3,972	0	991
	Net Load	-3,693	-599	-66	490	4,611	0	1,019
CA North	Load	-2,323	-437	-16	532	3,099	1	878
	Net Load	-2,603	-482	-7	537	3,084	1	896
ERCOT	Load	-6,028	-1,408	-38	1,469	6,509	1	2,153
	Net Load	-6,118	-1,415	-32	1,476	7,115	1	2,152

Table 4-7. Relationships Among Load Statistics and Installed Wind Capacity

Region	Offshore Wind Energy Penetration	Ratio of Max. Load to Wind Capacity	Ratio of Min. Load to Wind Capacity
PJM	6.8%	10.1	3.7
New England	38.4%	2.4	0.8
Carolinas	11.0%	5.8	2.1
MISO	4.2%	16.1	6.2
NWPP	7.7%	11.4	4.9
CA North	10.1%	10.1	3.1
ERCOT	2.7%	28.5	9.6

4.3.2 LOAD AND NET LOAD DISTRIBUTIONS

This section studies how load distributions were altered when offshore wind was added to each region. The analysis began by looking at the duration curves shown in Figure 4-22 and Figure 4-23. As expected, the largest change happened in New England, where the load distribution was greatly affected throughout all hours of the year. A small number of hours had negative net load. On the other end of the spectrum, the changes in net load for MISO and ERCOT were negligible. The remaining regions experienced moderate changes in their profiles, but the ratio of peaks to valleys increased for all of them. Net load tended to decrease more during low-load hours, because wind generation tended to be higher during spring nights, when loads are smaller. Northern California is the exception, because its duration curve shifted downward. As previously noted, the wind generation characteristics in that region are different from the rest.

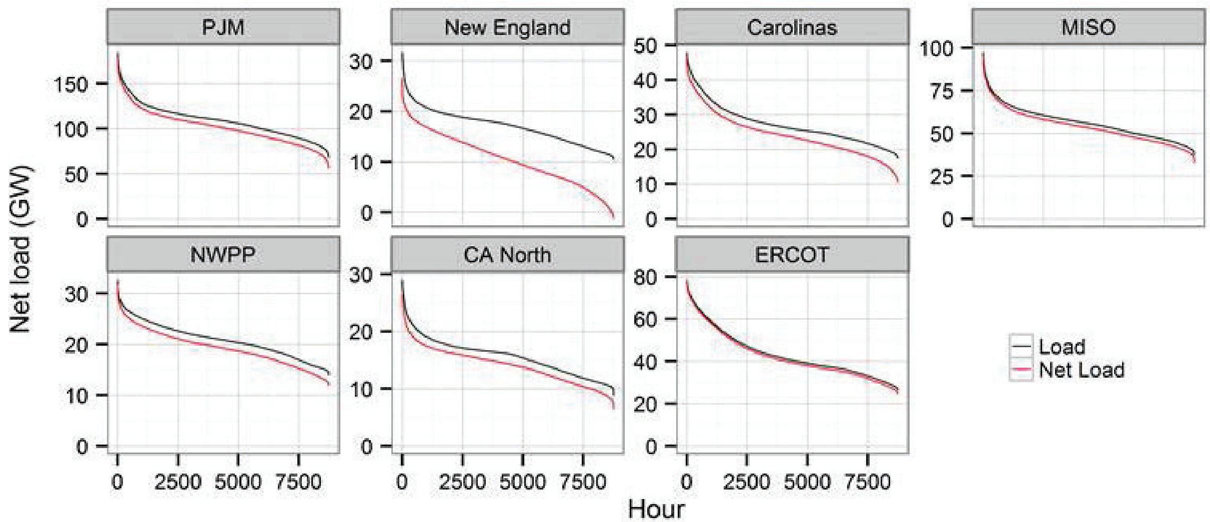

Figure 4-22. Load and net load power duration curves

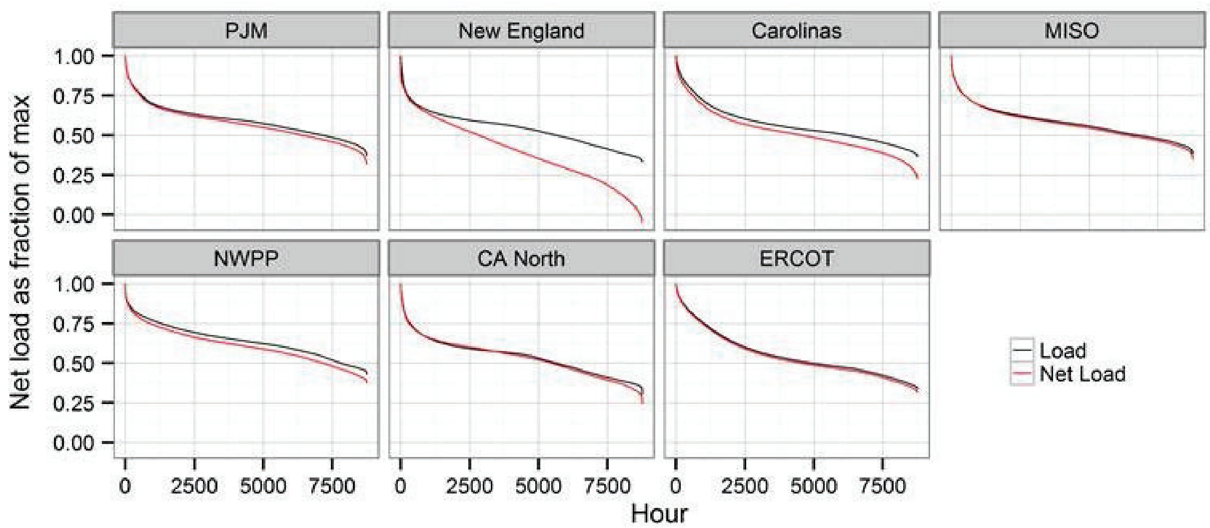

Figure 4-23. Load and net load power duration curves normalized to the peak value

Figure 4-24 shows average generation by month for each region. Most of the regions peaked during the summer, with the exception of NWPP. All of the eastern regions and ERCOT experienced a larger shift in net load during spring and winter; whereas NWPP experienced the greatest change during the summer, when loads are smaller. Northern California is a summer peaking system, and offshore wind generation is the largest during those months.

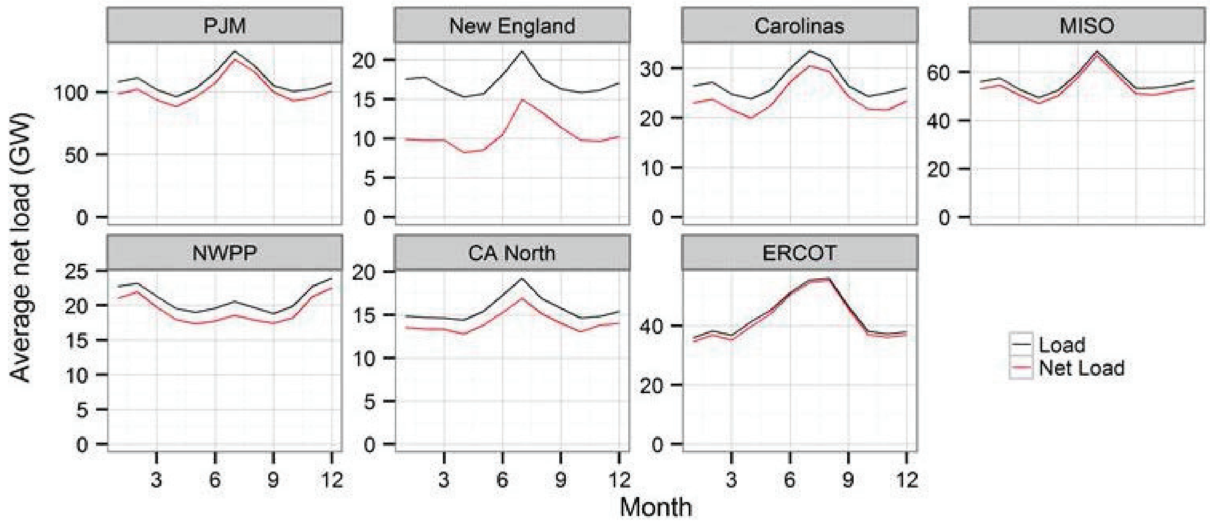

Figure 4-24. Average monthly load and net load by region

Next, typical daily profiles were examined, starting with average profiles for the entire year (Figure 4-25). The largest changes were observed in New England and the Carolinas. A closer look at seasonal profiles (Figure 4-26), especially in the changes as a fraction of daily peaks (Figure 4-27), revealed that New England's peak-to-valley ratio increased dramatically throughout the year. The lowest net load values in that region were experienced during the spring and fall. The biggest changes in the net load shapes were found in the Carolinas, which experienced a flattening of peak load hours during the spring and summer (because of the afternoon wind power increase) and lower relative minimum values during the spring and fall. The remaining regions were less affected; thus, their shapes remained mostly unchanged.

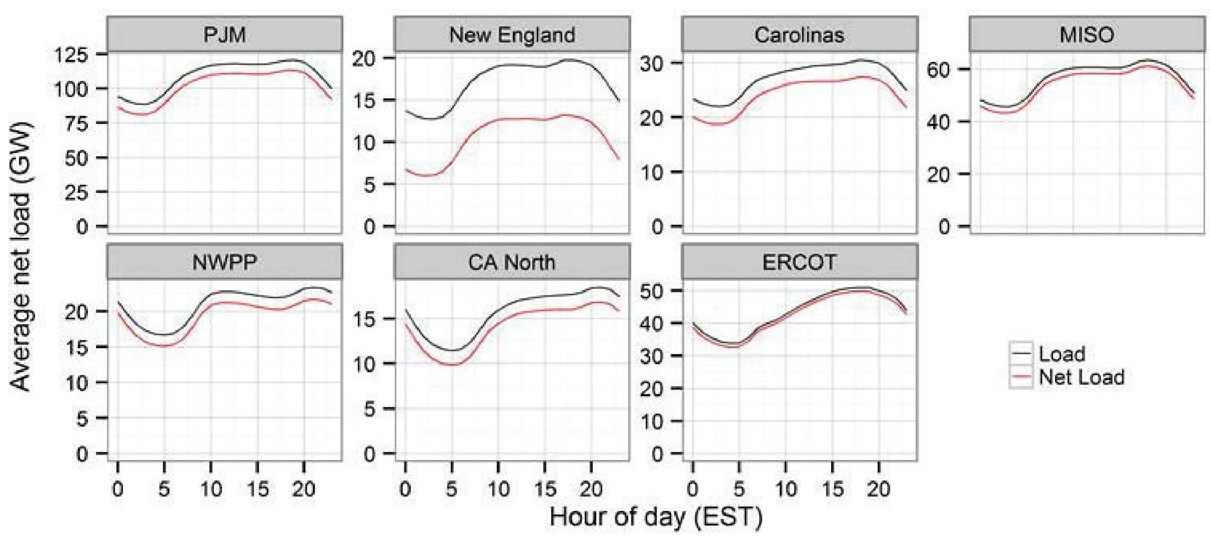

Figure 4-25. Average daily load and net load profiles by region

Contour plots showing average load and net load by month and hour of day were examined and the most interesting are shown here. New England (Figure 4-28) showed a dramatic decrease in load levels throughout the year. The general locations of maxima and minima were maintained, but the differences between the two were larger. Northern California (Figure 4-29) and the Carolinas (Figure 4-30) experienced much more subtle changes, with the biggest change being lower net load values during spring and fall mornings. The plots for other regions, which presented even smaller differences, are included in Appendix B.

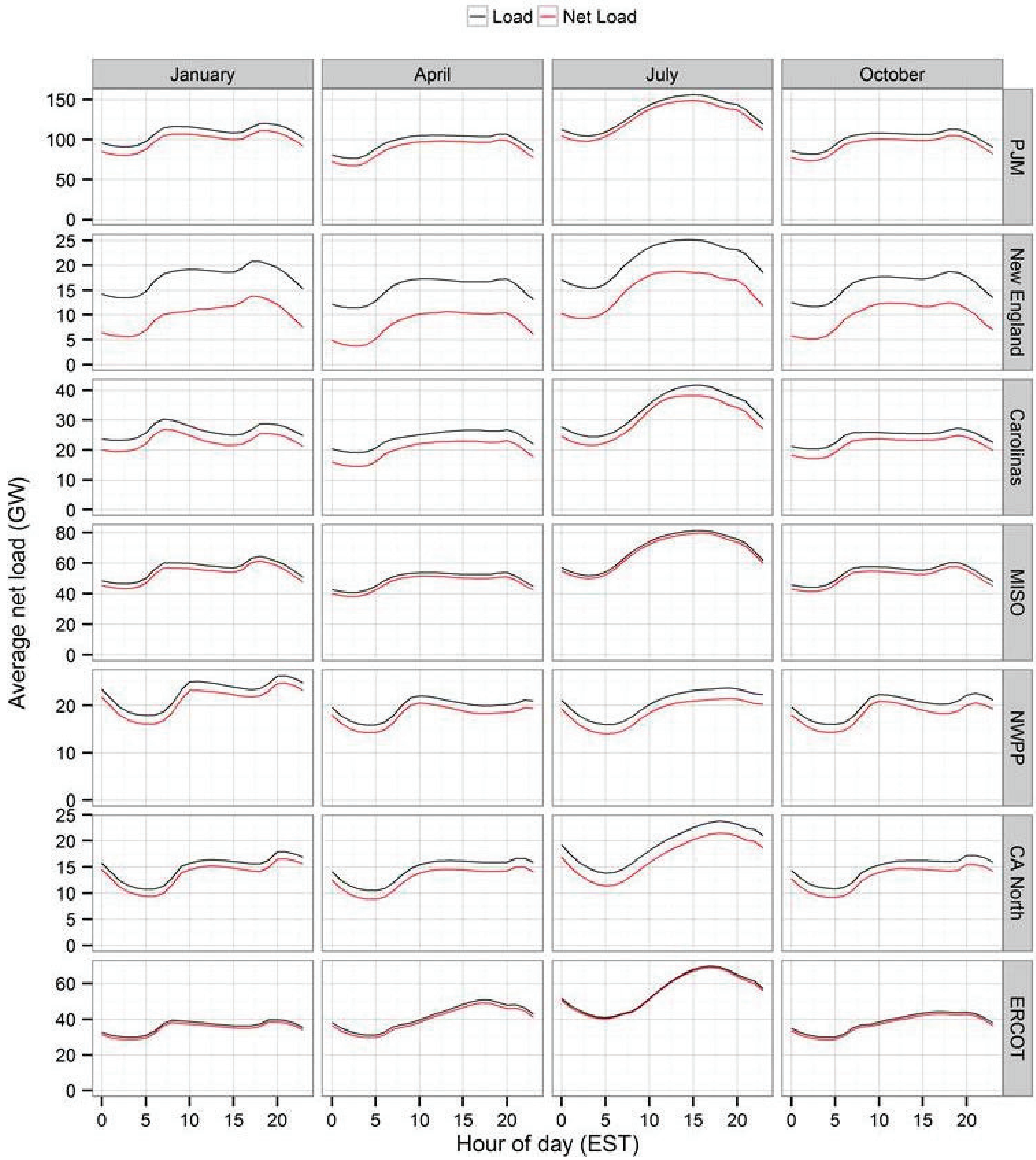

Figure 4-26. Average load and net load shapes for selected months

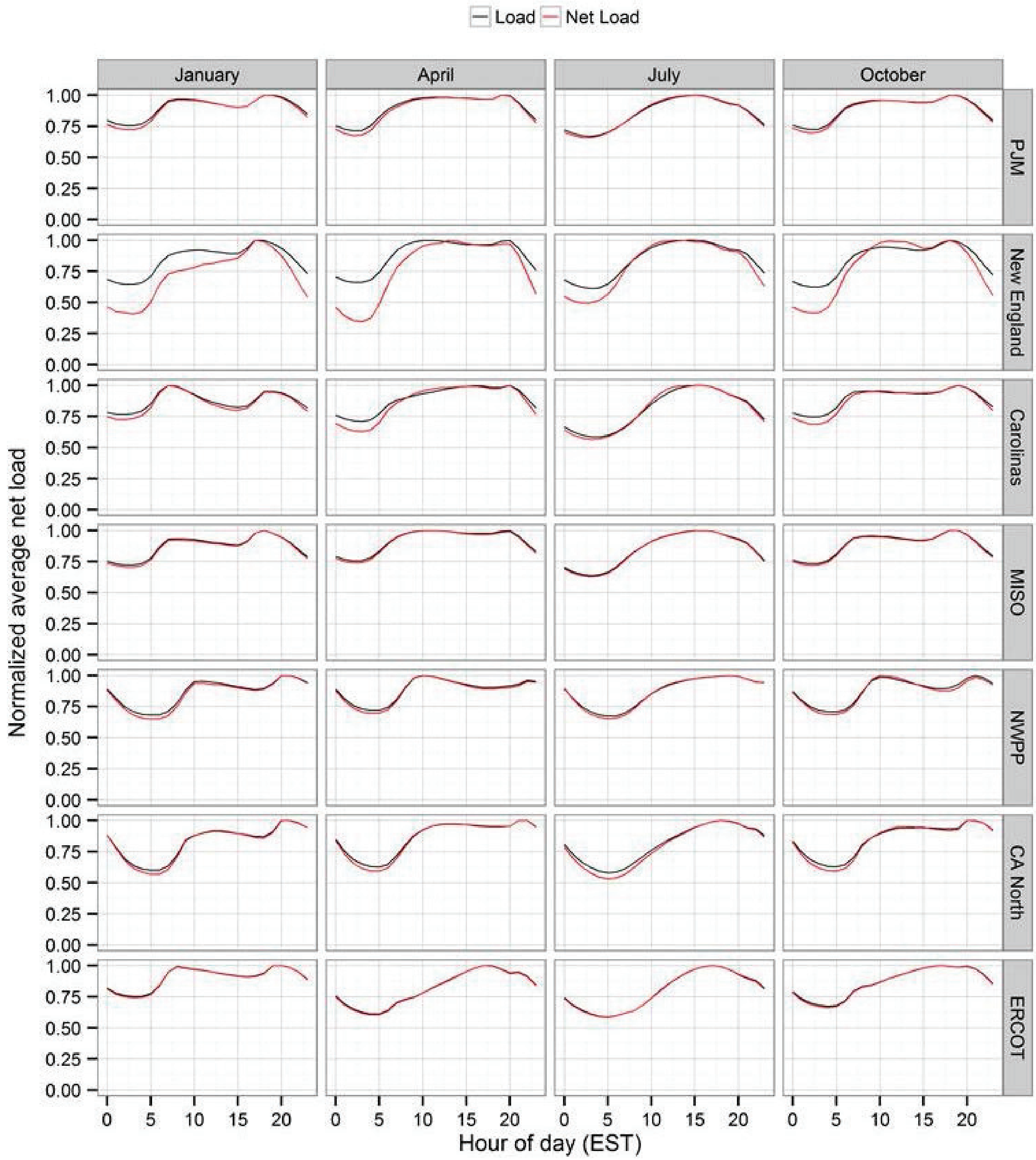

Figure 4-27. Average load and net load shapes for selected months normalized to the month average peak value

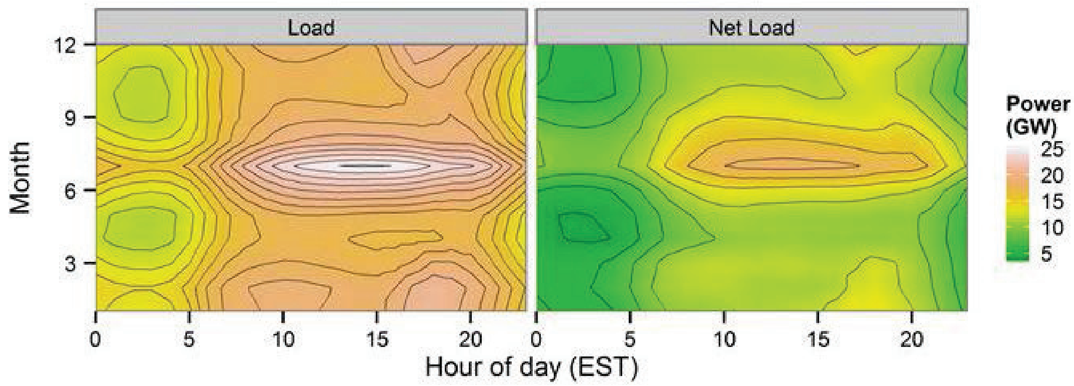

Figure 4-28. Contour plots showing average load and net load by month and hour of day for New England

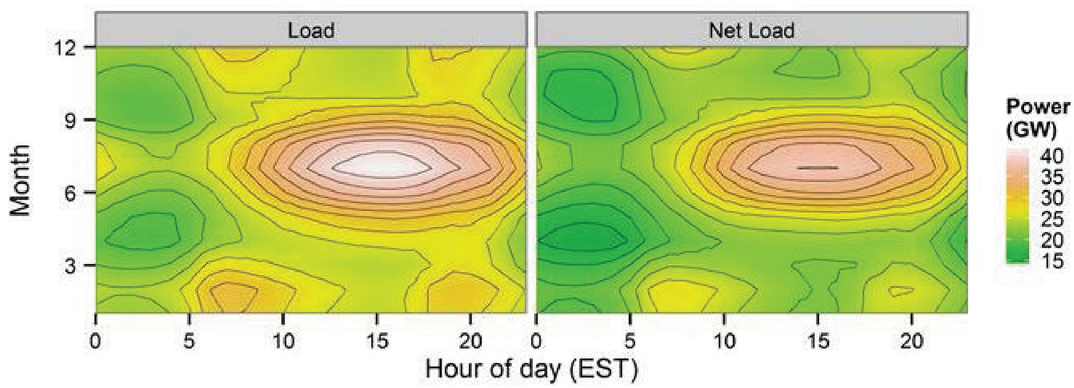

Figure 4-29. Contour plots showing average load and net load by month and hour of day for the Carolinas

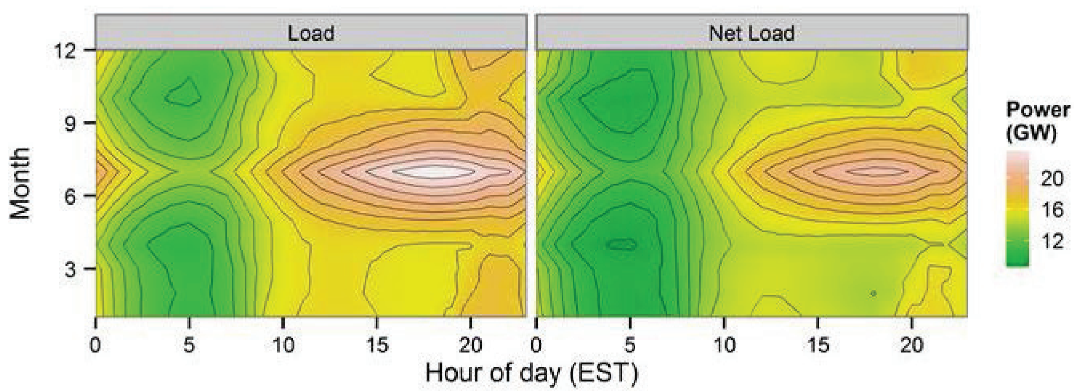

Figure 4-30. Contour plots showing average load and net load by month and hour of day for Northern California

4.3.3 HOURLY NET LOAD VARIABILITY

After examining the changes in net load power, the effects of offshore wind in net load variability are considered by analyzing hourly ramps. Figure 4-31 compares load and net load duration curves to ramps by region. As the summary statistics indicated, the changes were subtle for most regions. The biggest differences were the increases in extreme values for PJM, NWPP, the Carolinas, ERCOT, and Northern California. The curves for MISO were indistinguishable from each other. In New England, the big effects of offshore wind on the net load shape did not create dramatic changes in ramps. Extreme ramp values increased significantly, but ramps increased only marginally.

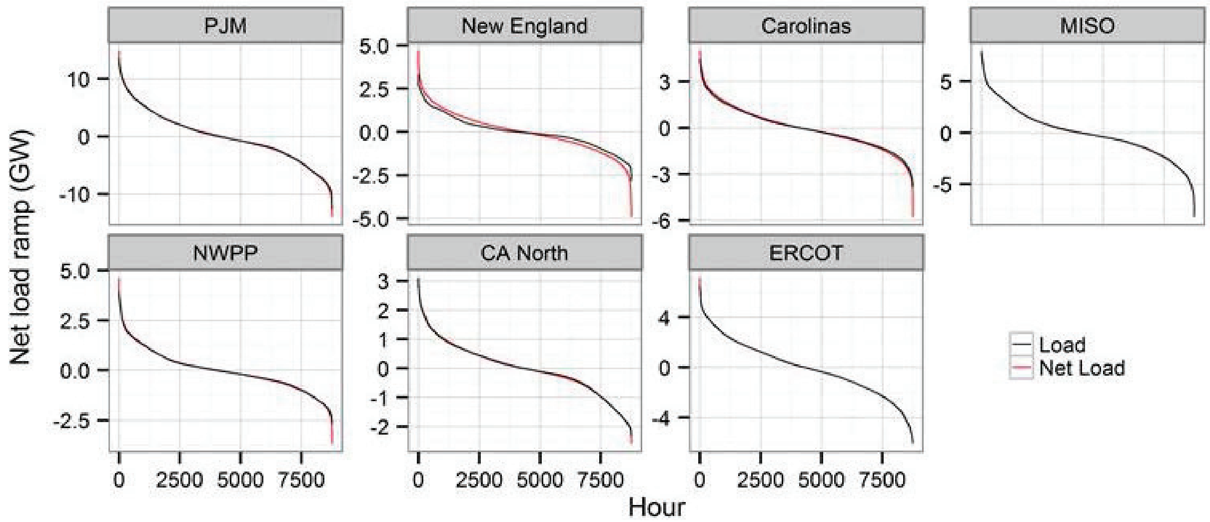

Figure 4-31. Hourly load and net load ramp duration curves

Figure 4-32 shows box plots representing typical load and net load distributions for the entire year. Similar figures for a few months are included in Appendix B. To simplify the comparisons among load and net load, the box plots in Figure 4-33 present side-by-side comparisons of load and net load hourly variability. The plots are further disaggregated in Figure 4-34, which shows separate distributions for one month per season. For the most part, net load ramp patterns remained the same. There were some instances in which variability tended to increase (such as in the Carolinas at night or during the fall and winter), but the maxima were the main changes. Again, New England was the exception, which had an overall increase in variability for most hours of the year, both in terms of extremes and the interquartile distances.

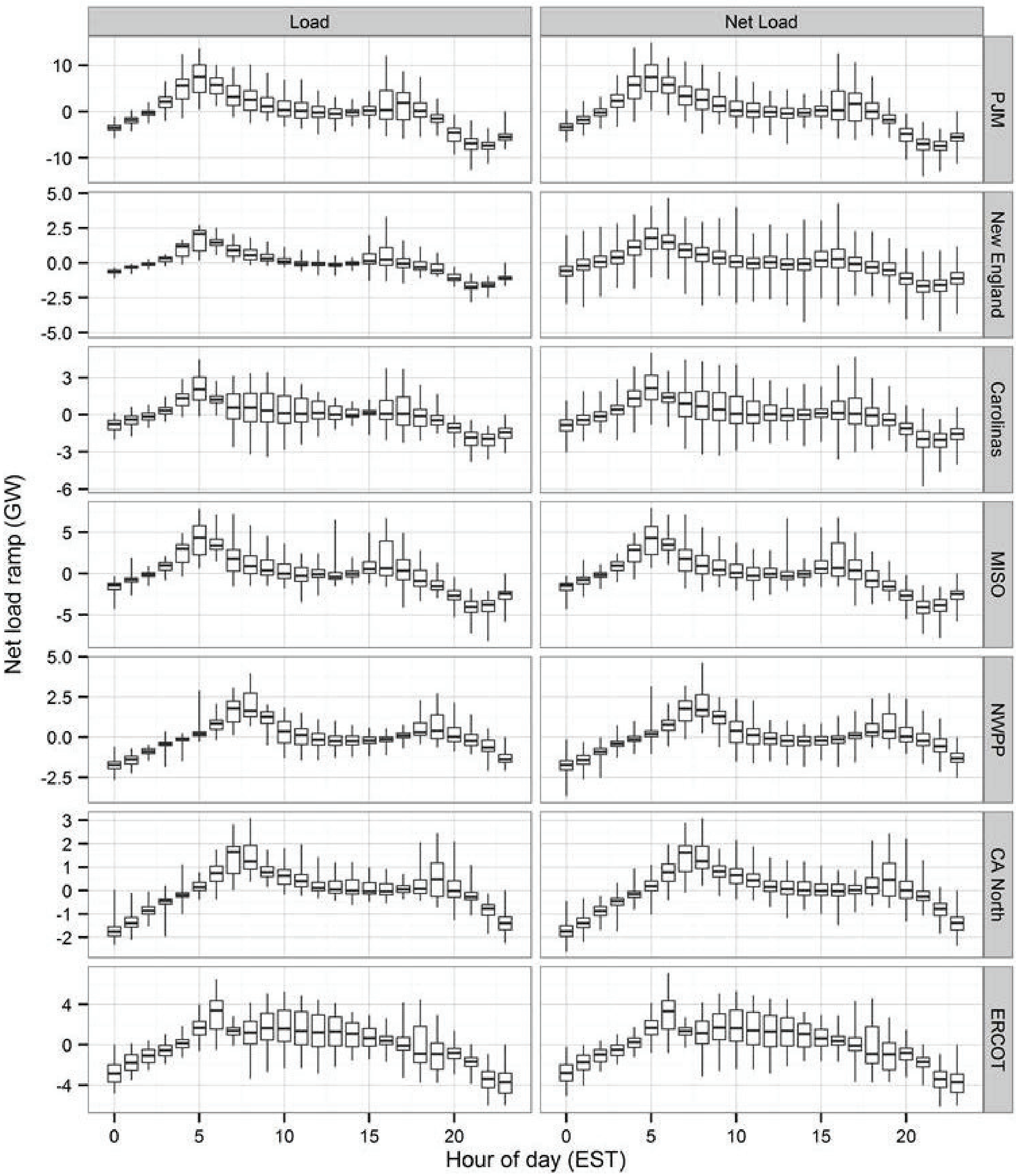

Figure 4-32. Boxplots showing load and net load hourly variability by hour of day

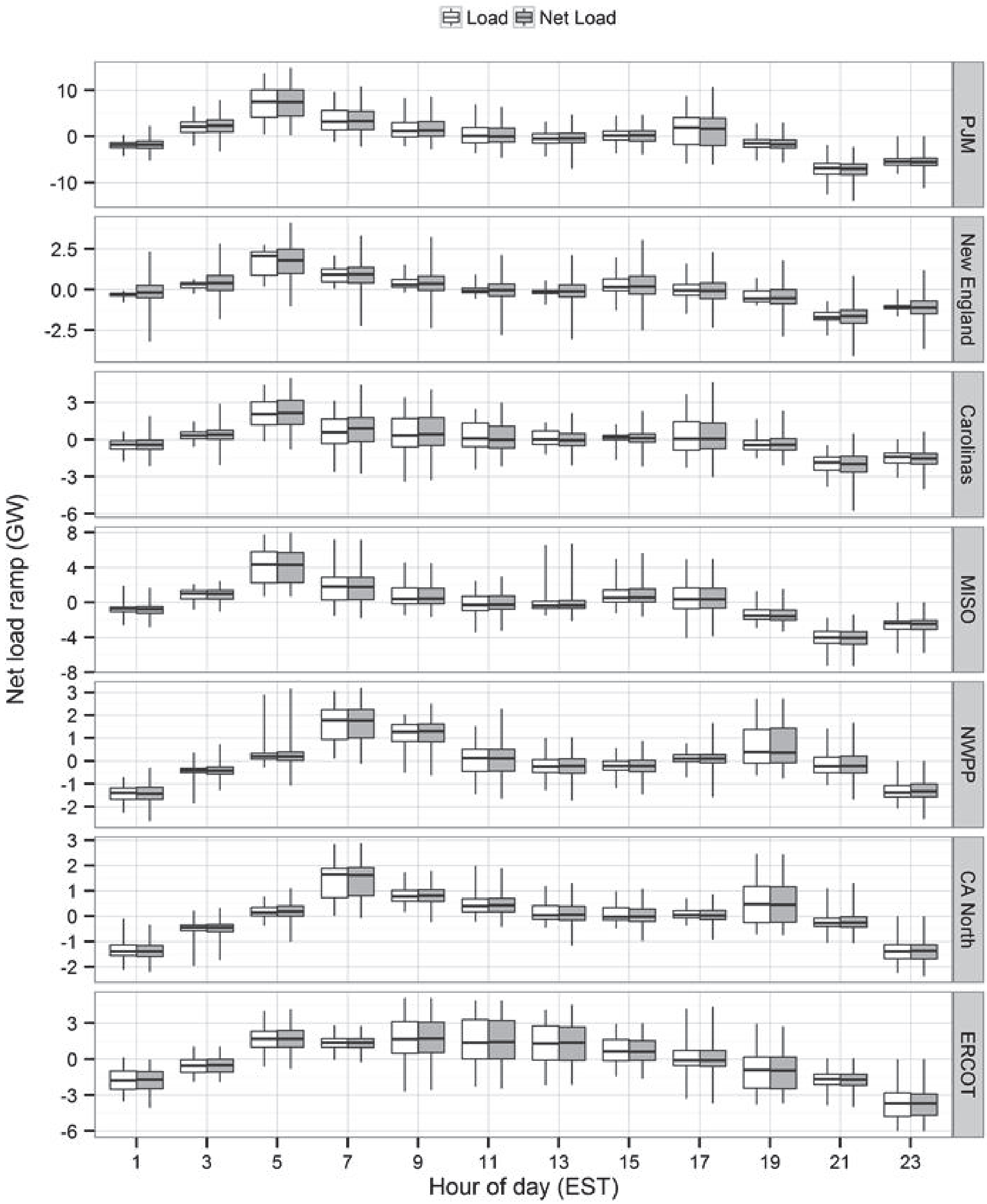

Figure 4-33. Boxplots comparing load and net load hourly variability by hour of day

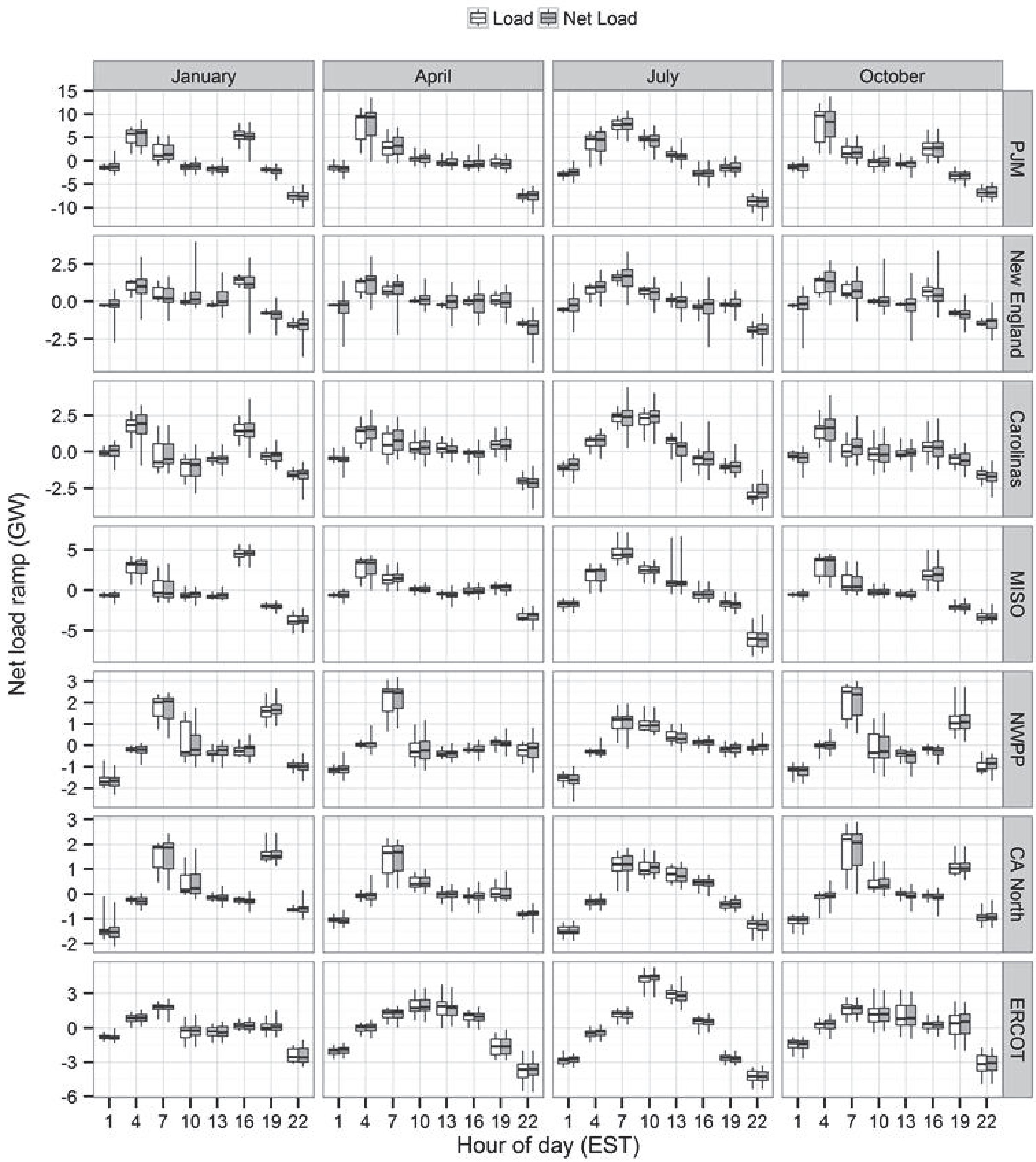

Figure 4-34. Boxplots comparing load and net load hourly variability for selected months by hour of day

Contour plots showing average hourly ramps by month are presented for New England, the Carolinas, and Northern California in Figure 4-35, Figure 4-36, and Figure 4-37, respectively. The plots for the remaining regions are included in Appendix B. For New England and the Carolinas, the biggest differences were the larger upward ramps during summer mornings and larger down ramps during summer nights. Northern California and the other regions did not experience significant changes.

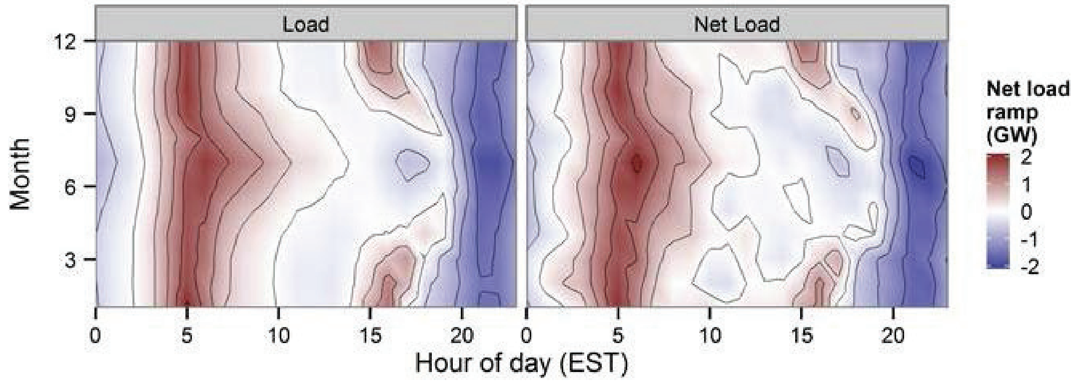

Figure 4-35. Contour plots showing average load and net load ramps by month and hour of day for New England

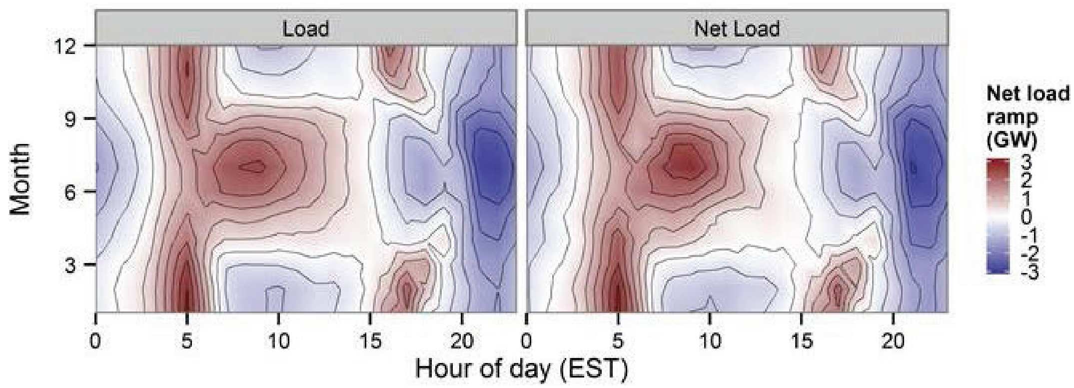

Figure 4-36. Contour plots showing average load and net load ramps by month and hour of day for the Carolinas

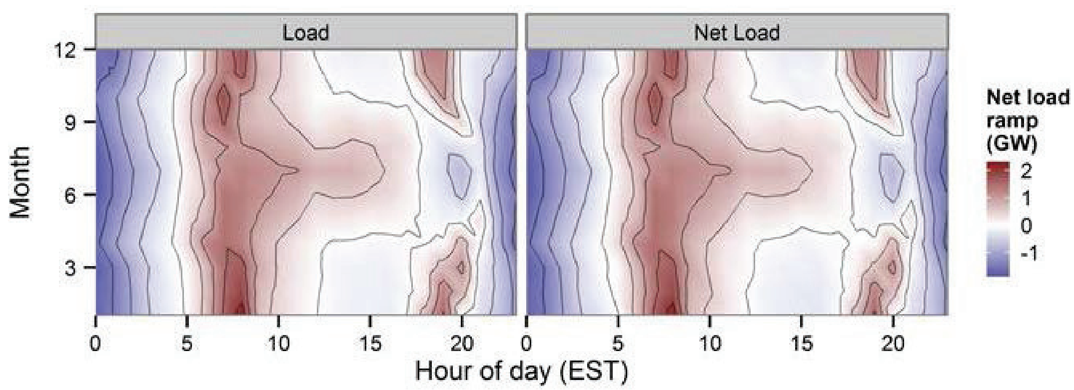

Figure 4-37. Contour plots showing average load and net load by month and hour of day for Northern California

4.3.4 DEPENDENCY OF LOAD AND OFFSHORE WIND VARIABILITY

Last, possible dependencies among load and wind ramps were examined. The plots in Figure 4-38 summarize the relationships among hourly ramps in load and wind time series. Each of these plots can be divided into four quadrants:

- Top right—Load and wind were rising, so they tended to cancel each other.
- Bottom left—Load and wind were decaying, so there was also a cancellation.

- Top left—Load was decreasing, but wind was increasing. As a result, net load decreased faster than the load, and other units needed to back down. In this instance, wind could be curtailed to prevent fast net load down ramps.
- Bottom right—Load was increasing, but wind was decreasing, making net load increase faster. This is the most problematic quadrant, because the only corrective measure would be to increase generation output from other generators.

These plots show that wind and load variability were largely uncorrelated in the hourly timescale for all seasons. Large outliers for either wind or load were not any more common in the bottom right quadrant than in the others. Additionally, these plots present the relative magnitude of load and wind hourly variability. In some regions (such as New England and the Carolinas), the variability of both was similar; whereas in others (e.g., PJM, MISO or ERCOT), the load variability was several times larger. These observations are consistent with previous findings in this section.

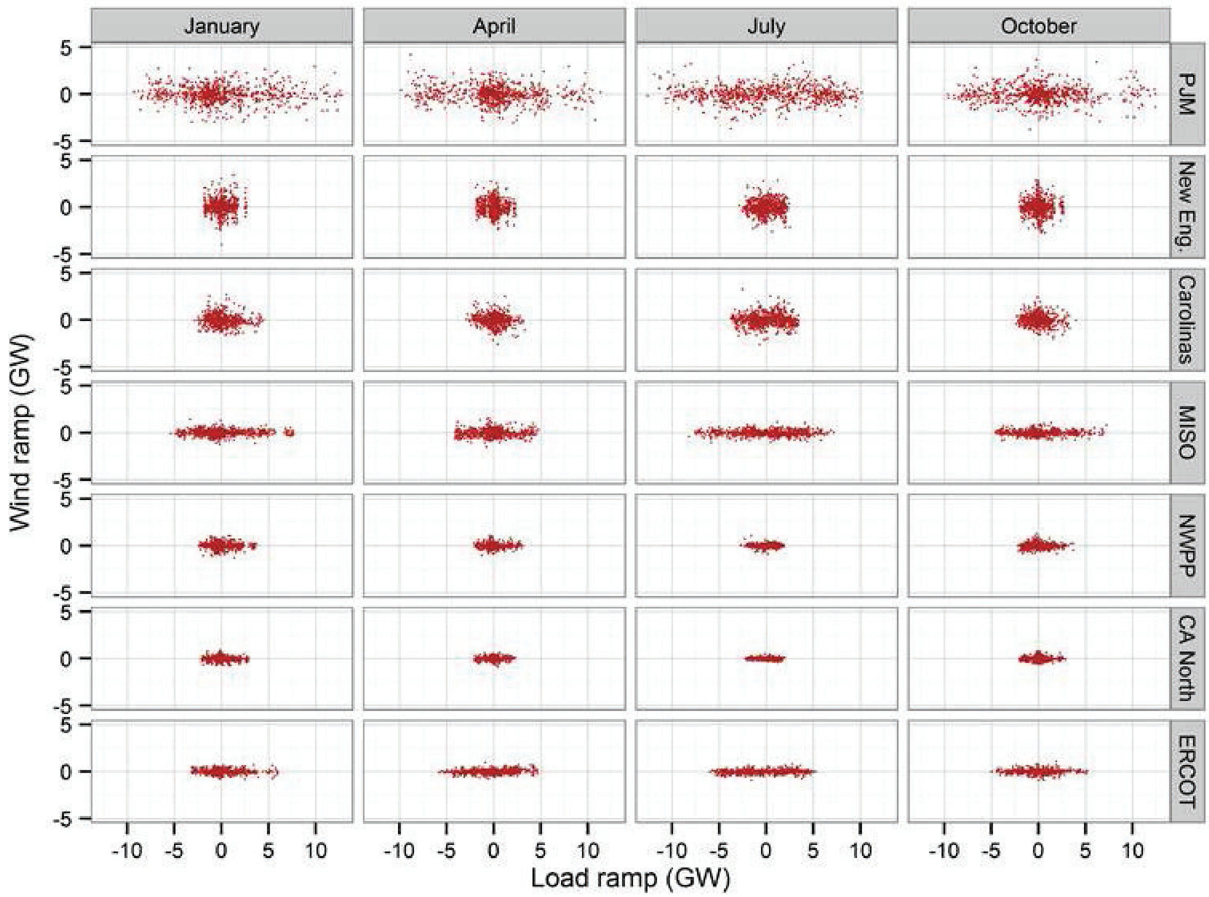

Figure 4-38. Offshore wind ramps versus load ramps by region for selected months

4.4 Effects on Regulating Reserve Requirements

The previous sections suggest that the behavior of offshore wind variability was similar to that of onshore wind [5][7]; thus, methods to integrate onshore wind power could be extended to incorporate offshore wind. In particular, this section focuses on the change in regulating reserve requirements caused by the presence of offshore wind in the seven regions.

Although the use of operating reserve is ubiquitous, there is no universal methodology to determine the amount that should be carried, and virtually each system around the world follows different procedures.

The advent of variable generation may raise the importance of different forms of both upward and downward reserve and the method of determining the amount needed [8]. In traditional power systems, requirements are based on heuristic needs that have been in place for decades. These methods are typically static and rarely based on updated system information in real time.

With the rapid increase in the penetration of variable generation, researchers and system operators alike have been developing new methods for determining operating reserve requirements based on more complex characteristics of variability and uncertainty [9]. Currently, only a few selected regions take into account the impact of wind in their regulating reserve methods. For instance, the determination of regulating reserve requirements in ERCOT is based on calculations of 5-minute net load variability [10]; whereas in the California ISO the requirements are based on the analysis of 1-minute net load variability [11]. Other regions, such as MISO [12], acknowledge that the current impact of wind on short-term forecast errors and variation is low and therefore do not include it in their calculations.

The methodology [13] developed for Phase 2 of NREL's *Western Wind and Solar Integration Study* [7] was used to calculate regulating reserve requirements. Because there was no single unified methodology to calculate regulating reserve requirements, the NREL study encompassed several regions across all three U.S. interconnections, and there existed a significant penetration of offshore wind in some of those regions. The impact from the addition of offshore wind was calculated by comparing the requirements with and without offshore wind. The requirements were calculated for each individual GridView region. Following is an explanation of the methodology and the application to this study.

Because short-term variations in wind power output are small, persistence forecasts are good predictors with which to calculate uncertainty. For instance, for an economic dispatch model run in 5-minute intervals (and assuming that 5 additional minutes are required to perform calculations and dispatch communications), 10-minute persistence forecasts would be used to estimate the uncertainty that a power system must handle between dispatch points. Forecast errors can be calculated by comparing the forecast to the actual power output. As previously observed, wind forecast errors—which equal wind ramps when using persistence forecasts—are highest at moderate total wind production levels. The magnitude of the errors decreases toward the extremes. Figure 4-39 represents this behavior for the PJM region.

Confidence intervals (represented as red and blue lines in Figure 4-39) were used to determine up- and down-reserve requirements, so that a certain percentage of forecast errors was covered by the reserve. Figure 4-39 shows the range of power (horizontal axis) divided into 10 groups with the same number of points. For each group, the average power was calculated as well as the confidence intervals that cover 95% of the forecast errors. The confidence interval bands were then interpolated from the group averages. For power values beyond the first and last group mean point, the requirements were kept constant in a simplified conservative approach. Figure 4-40 represents the results of applying the same process to all the regions in the study.

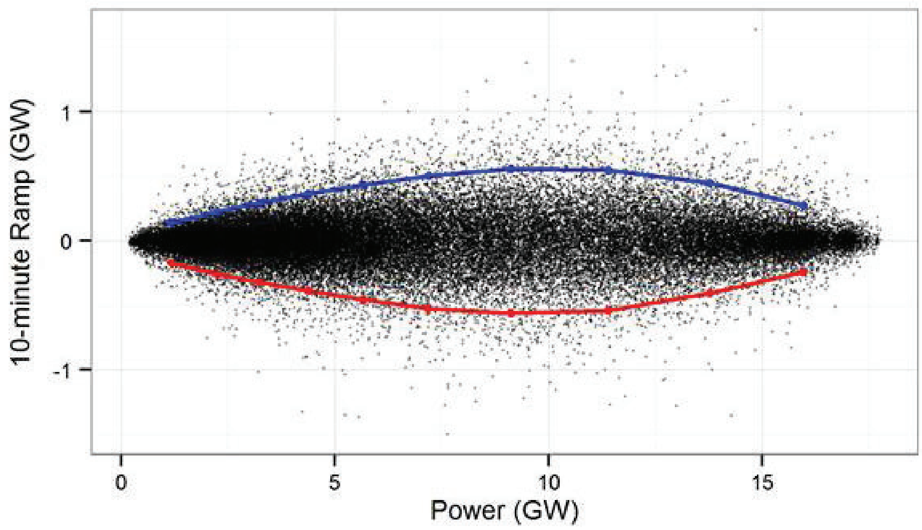

Figure 4-39. Offshore wind forecast errors with 95% confidence intervals

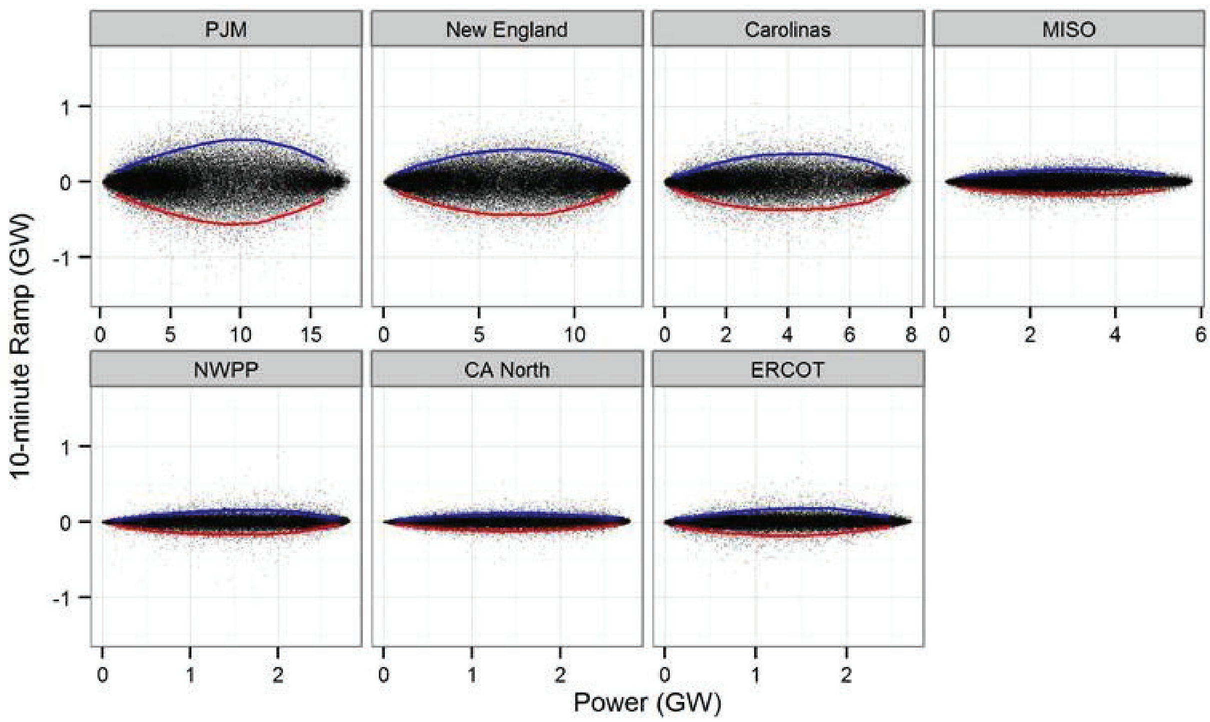

Figure 4-40. Offshore wind forecast errors with 95% confidence intervals for all regions

Given that offshore wind and load variability were independent in hourly and sub-hourly time frames, the total reserve requirement was calculated as the geometric sum (i.e., root mean square sum) of the contributions from load and wind, as follows. For load, typical requirements were set as a percentage of load (1% in this case[4]). For offshore wind, the dynamic reserve scheme presented above was used.

[4] Although the determination of regulating reserve requirements due to load varies between different systems, simple rules of thumb (such as 1% of load) are typically used in integration studies [5,7] or industry (e.g., the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee).

$$
\begin{aligned}
RegulatingReserve &= \sqrt{LoadReserve^{2} + WindReserve^{2}} \\
&= \sqrt{(0.01 \times Load)^{2} + \Phi_{10-min\ Wind}{}^{2}}
\end{aligned}
$$

Each hour of the year was calculated. For instance, Figure 4-41 and Figure 4-42 show load, offshore wind power, and reserve time series for a few days in April for PJM and the Carolinas. The reserve components (wind and load) are represented, along with the combined total. Upward components are represented as positive values; downward components are represented as negative. In PJM, the load component of the reserve was the main contributor to the total requirement, because it was larger than the wind component. In the Carolinas, the load and wind components alternated as the largest; thus, the total requirement followed a combination of the two shapes. In both cases, upward and downward reserve requirements looked very similar in magnitude.

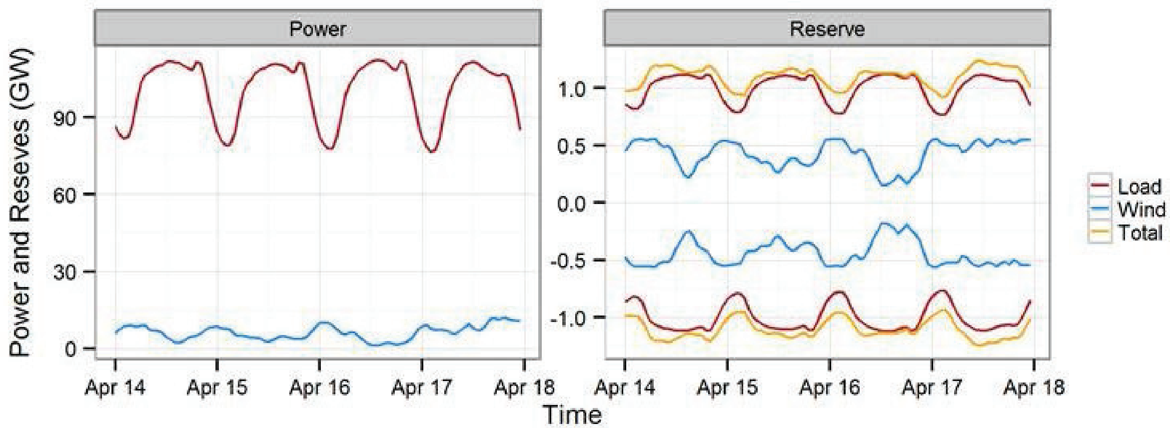

Figure 4-41. Sample load, wind power, and reserve time series for PJM

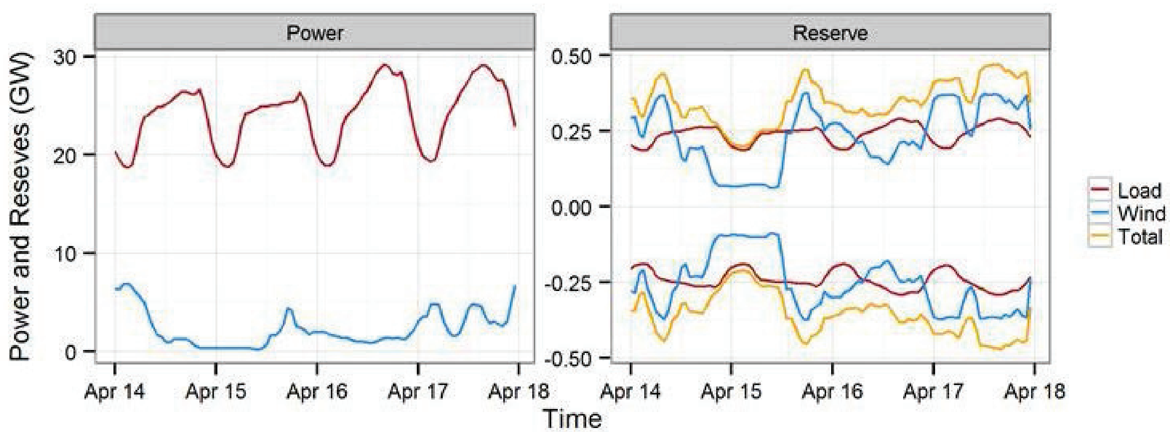

Figure 4-42. Sample load, wind power, and reserve time series for the Carolinas

Figure 4-43 compares the load and offshore wind components to the total reserve requirements for all seven regions, and Table 4-8 summarizes the total requirements. Again, upward and downward requirements were very similar. Offshore wind had a small effect on the final requirements for most regions, with the exception of New England and the Carolinas. These regions had the highest penetration of offshore wind relative to load.

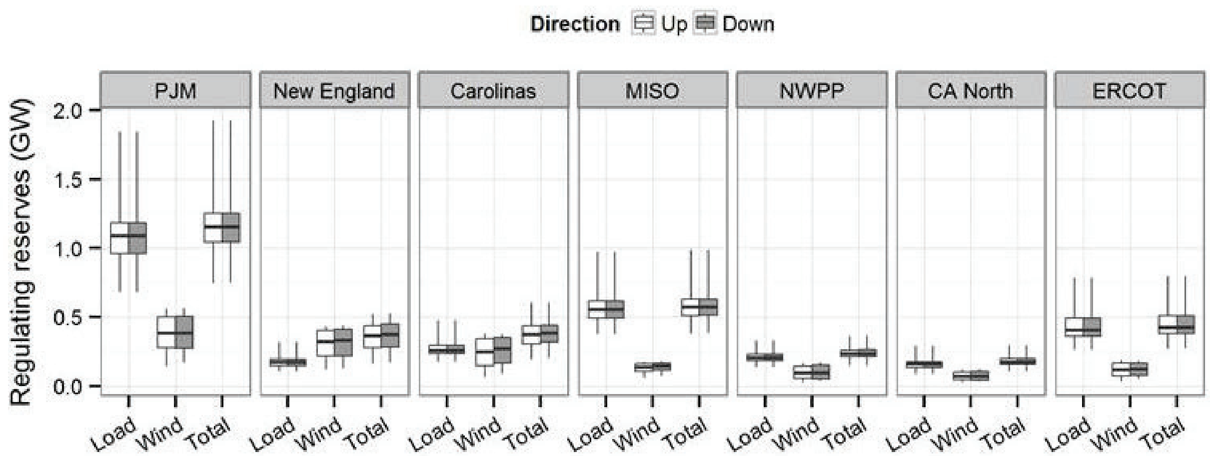

Figure 4-43. Reserve components and total requirements by region

Table 4-8. Load and Total Reserve Requirements and Differences

Region	Load Up/Down (GW-h)	Total Up (GW-h)	Total Down (GW-h)	Increase Up	Increase Down
PJM	9,461	10,105	10,117	7%	7%
New England	1,500	3,112	3,161	107%	111%
Carolinas	2,378	3,272	3,332	38%	40%
MISO	4,942	5,086	5,101	3%	3%
NWPP	1,836	2,053	2,075	12%	13%
CA North	1,376	1,541	1,544	12%	12%
ERCOT	3,810	3,973	3,981	4%	4%
TOTAL	25,303	29,142	29,310	15%	16%

4.5 Conclusions

This section examined the potential operational impact of deploying 54 GW of offshore wind in the United States. The capacity was not evenly distributed; instead, it was concentrated in regions with better wind quality and close to load centers. Most of the capacity was located in the East Coast regions, with additional capacity installed in the Great Lakes, ERCOT, and on the West Coast. The location of the offshore wind was determined with ReEDS and later refined using high-resolution data and numerical weather prediction models. These models were used to simulate 10-minute power profiles for the years 2004, 2005, and 2006.

A statistical analysis of offshore wind power time series was used to assess the effect on the power system. The behavior of offshore wind resembled that of onshore wind, despite the former presenting higher CFs, more consistent power output across seasons, and higher variability levels. Thus, methods developed to manage onshore wind variability can be extended and applied to offshore wind.

The western regions (Northern California and NWPP) presented the highest CFs (above 55%), although the installed capacity was relatively low (less than 3 GW). The profiles in those regions were also the most unique, with consistent high power generation during the summer months. The CF in New England, where more than 13 GW of wind were installed, was almost 50%. The CFs in the remaining regions averaged from 40% to 42%. Wind generation in the eastern regions, ERCOT, and the Great Lakes was higher during nights and spring months. Some regions, such as the Carolinas and PJM, presented singular daily profiles during the summer with consistent positive ramps in the afternoon as a result of sea breezes.

Wind variability was typically small, with most of the hourly ramps below 3% of nameplate capacity. That dropped to 1% for the 10-minute ramps. However, extreme values were much larger, from 10% to 35%, but rare. Overall, Northern California and NWPP had small variability, especially during the summer, when wind power output is high and sustained. Other regions presented less relative variability with more installed capacity or more geographic diversity. The variability of offshore wind had a very distinct relationship to power levels, similar to onshore wind. Variability tended to be largest when power output was in the midrange of installed capacity, and it decreased toward the extremes.

The impacts on net load were largest in New England, where almost 40% of the load could be provided by wind. There were a few hours when wind power surpassed load levels. Net load profiles shifted considerably, and the peak-to-valley ratio increased significantly. In other regions, the change was moderate. Northern California is the only region in which high loads and high wind aligned. All other regions experienced higher drops in net load during low-load hours.

The effects on net load variability were relatively small for most of the year, even in New England. The most significant changes were typically increases in rare and extreme ramp values. Load and offshore wind hourly variability were found to be independent, although the relative magnitude of both varied across regions. In New England and the Carolinas, both were very similar.

The methodology developed for Phase 2 of the *Western Wind and Solar Integration Study* was also used here to determine the increase in reserve requirements as a result of wind variability, because offshore wind behaves like onshore wind for this purpose: there is a clear dependency between power and forecast error, and wind and load ramps are independent. The biggest increase in requirement due to the addition of offshore wind was found in New England, where it more than doubled, followed by the Carolinas, which experienced a 40% increase. The remaining regions experienced a marginal increase. These reserve requirements will become an input of the production cost simulations in Section 6.5.

4.6 Section References

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5.0 TECHNOLOGY OVERVIEW

This section discusses various technologies available for collecting and transmitting offshore wind energy to shore for injection into one or more utility transmission systems. Before the technology can be quantitatively assessed, the state of the art and potential options must be understood. Significant work has been done within the wind industry on many of the components. This section evaluates these advancements and provides an overview of the issues involved.

5.1 General Offshore System Structure

To use the offshore resources, it is necessary to bring the energy produced to shore and inject it into the onshore transmission grid. To do this, as illustrated in Figure 5-1, three specific processes can be defined: production or generation, collection, and delivery. Each process has its own set of technology options. It is common within the industry to call the delivery system a "transmission" system, but because of its specific purpose in this context, and to avoid confusion with the onshore transmission network, the term *delivery* is used in this report.

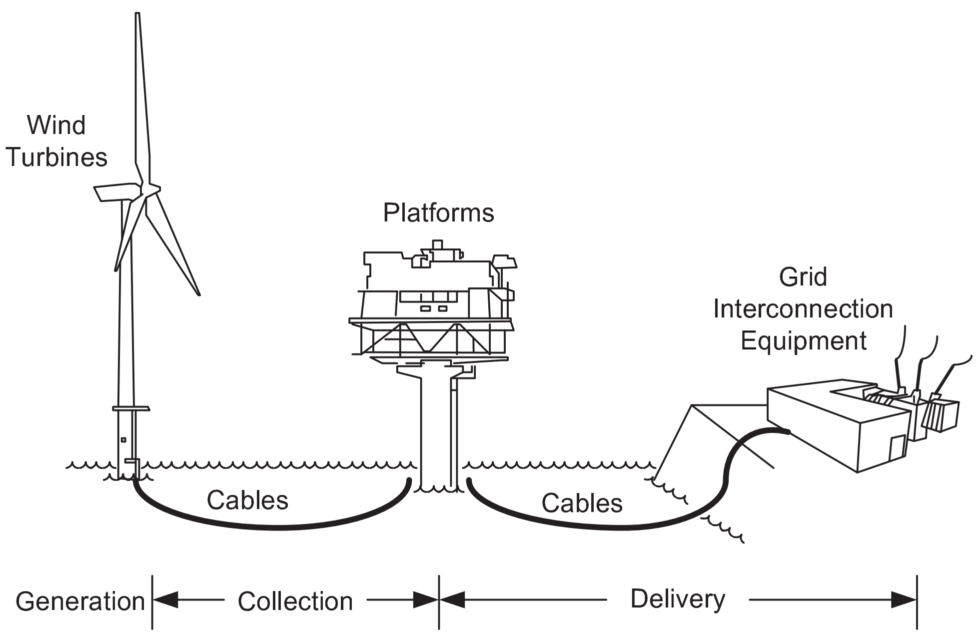


Figure 5-1. Generalized concept for an offshore wind energy system

A few of the driving questions for the technology selection of each process include (but are not limited to):

- What options are currently available?
- What new options are possible (but not implemented) with current technology?
- What options could be made available with foreseeable technological advancements (and what advancements are needed)?
- What are the benefits and drawbacks of each possible technology option?
- What are the economics of each option?
- How do the technology options for each process interact at the interface points?

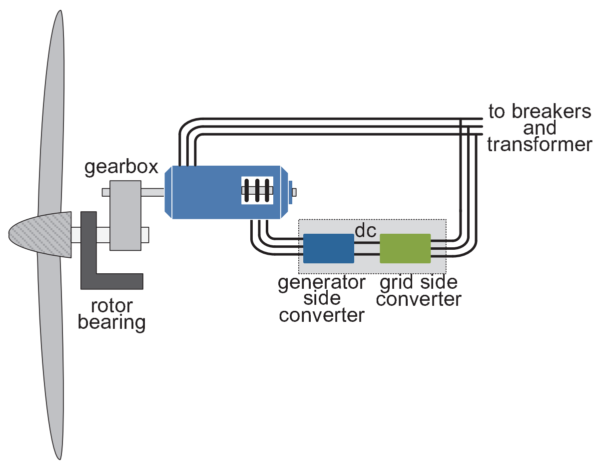
To begin exploring these issues, this section provides a review of technologies discussed in public sources, beginning with a brief background on the current generation technologies.

5.2 Wind Turbine Generator Types

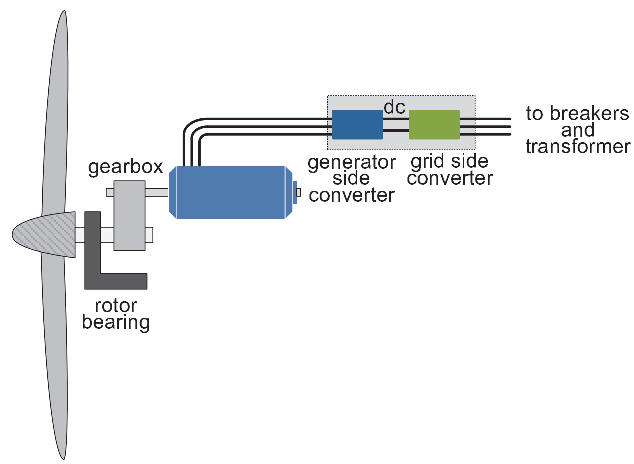
In general, there are four basic types of wind turbine generators (WTGs) currently in use in wind power plants. These have been categorized by the Institute of Electrical and Electronic Engineers (IEEE) as Type 1 through Type 4.

- Type 1—A directly connected asynchronous machine, typically with a squirrel-cage rotor
- Type 2—A directly connected asynchronous machine with a wound rotor connected to an external resistor
- Type 3—Commonly known as a doubly-fed induction generator (DFIG) machine
- Type 4—Also known as a full-converter wind turbine

Types 1 and Type 2 are seldom used in modern installations, and it is doubtful that they will be used for offshore applications. However, Type 3 and Type 4 are quite prominent in the plans for both onshore and offshore applications. Figure 5-2 illustrates the Type 3 and Type 4 general configurations.



(a) Type 3



(b) Type 4

Figure 5-2. Current wind turbine types and their general configurations

The Type 3 DFIG turbine (Figure 5-2 (a)), is a flexible machine and has been the most widely used for land-based installations in the United States for several years. Its popularity is largely due to economic factors. Like the Type 2 turbine, a wound-rotor machine is used, but a partial-power AC-DC-AC converter, connected between the rotor and the AC grid connection replaces the external resistor. The converter is used to supply a carefully controlled voltage to the machine rotor to modify the machine operating characteristics and allow it to provide more efficient performance over a wider range of speeds than the Type 1 and Type 2. The partial-power converter makes it less expensive than a Type 4 machine, and its operating flexibility and control gives it attractive production characteristics. One limitation is that the converters acting on the rotor give the DFIG a greater propensity to machine self-excitation in the presence of series compensation than other directly connected machines. For offshore applications, the use of series compensation is not expected to be a popular choice, but this raises little concern.

The Type 4 turbine (Figure 5-2 (b)) also uses an AC-DC-AC converter, but it is rated for the full capability of the system and is placed between the machine and the electric grid. Because of this feature, it is often referred to as a full-converter WTG. This arrangement provides the machine a beneficial level of isolation from the AC grid, and the type of machine used as a generator is much less important; synchronous, induction, and even DC machines can, in theory, all be used for the generator. In fact, the AC frequency used on the machine side can be completely different than that of the grid to which the WTG system is connected, allowing a very wide range of potential operating speeds on the wind turbine side of the converter. The only limitations are the converter equipment and its controls.

Typical output voltage for the WTGs is between 575 V and 690 V, and the connection to the collector system is made through a step-up transformer to raise the voltage. The typical collector voltage used in the United States is 33 kV or 34.5 kV, but any other voltage is possible, and the economics of the design should drive the selection. The typical power rating for an individual turbine is between 1.5 MW and 5.0 MW, with the larger sizes generally being used for offshore applications.

Both Type 3 and Type 4 turbines are used offshore. The Type 3 turbine's power rating can often be higher, because the rating of the converter can be smaller than that of the generator. With the Type 4 machines, the converters must be capable of handling the full output of the generator.

The converters can be similar to those used for low-voltage motor drives and operate at line voltages below 1,000 V, or they may be of medium-voltage equipment with an output line voltage of approximately 3 kV. A higher line voltage allows for lower line currents for a given machine rating.

5.3 Collection and Delivery

A wide variety of topologies are possible for both the collection and the delivery system, and, in theory, either AC or DC systems can be used for each. The conventional AC arrangement is illustrated in Figure 5-3. The number of turbine strings (or clusters) and their size will depend on the plant capacity and other technical decisions made during the design stage. The reactive compensation shown in the figure is typically necessary to compensate for at least part of the cable charging, which can limit the useable power that can be transmitted by the cables. It is more convenient and cost-effective to place this onshore, but it is also possible and may be desirable or necessary to have some compensation at the platform.

The interconnections shown to other platforms may or may not be used, depending on the design of the system, and they can be used at the collector voltage level, the delivery voltage level, or both.

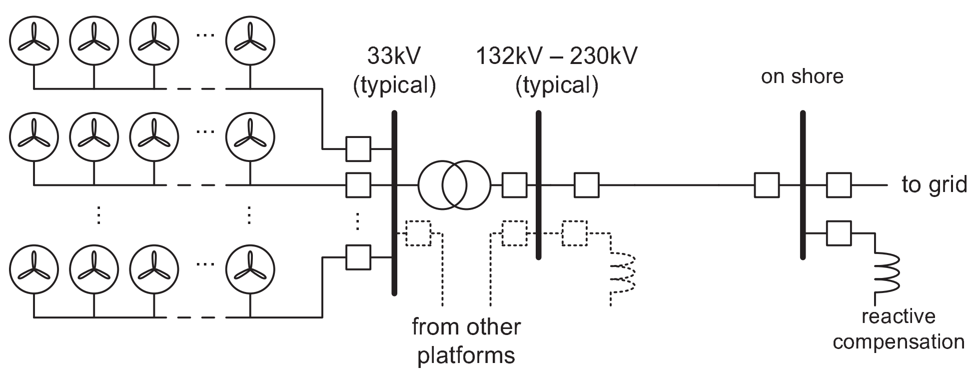


Figure 5-3. Conventional AC offshore wind collection and delivery system

As far as the authors have yet been able to determine, DC has been used only for the delivery system to date, with the conventional arrangement as shown in Figure 5-4. This differs from the previous system primarily because of the use of voltage source converters (VSCs) to rectify the offshore AC to DC and inverting the DC back to AC onshore.

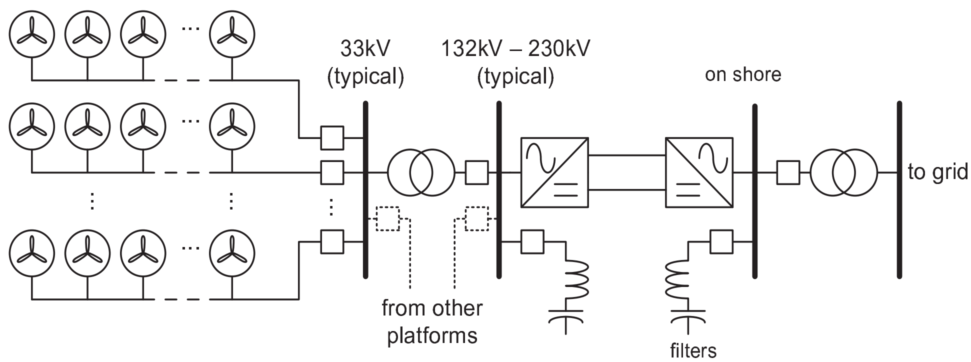
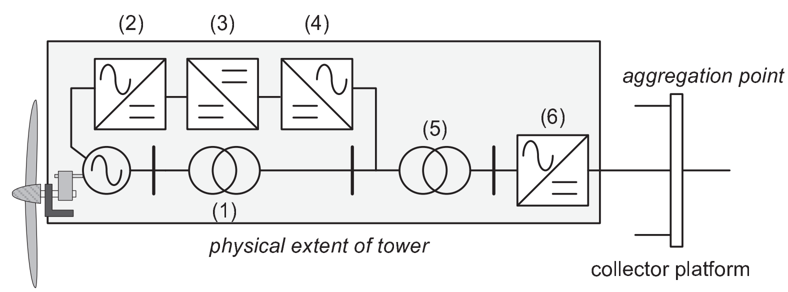


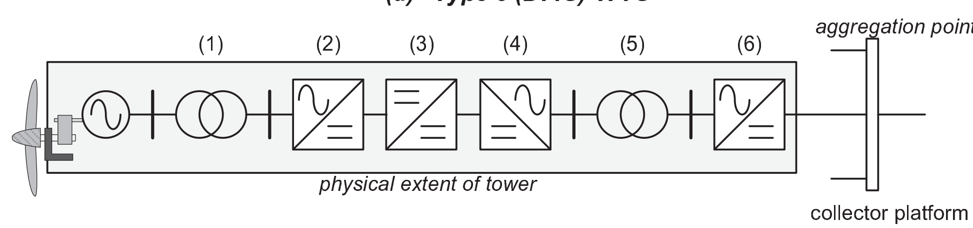
Figure 5-4. Conventional AC offshore wind collection with DC delivery system

The collector systems to date have been AC strings connected via radial cables to the collection platform, as shown in Figure 5-4. However, several options could potentially be implemented in conjunction with turbine manufacturers that would offer flexibility in the selection of the collector system design and topology. Ultimately, there is a close relationship between the collector system, the delivery system, and the WTG type selection.

For instance, consider the entire train of equipment that could exist between the generator and the point of aggregation (typically the collector platform), as illustrated in Figure 5-5. Figure 5-5 (a) is appropriate when considering a Type 3 machine; Figure 5-5 (b) is appropriate when considering a Type 4 machine.



(a) Type 3 (DFIG) WTG



(b) Type 4 (full-converter) WTG

Figure 5-5. Possible components for the collector system electrical equipment train

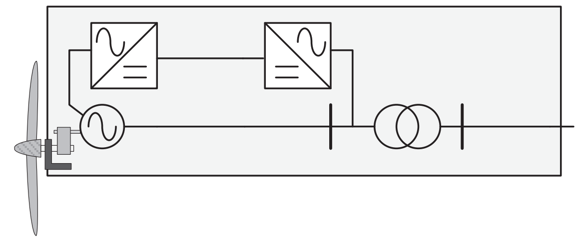
For a Type 3 WTG, potential equipment other than the generator itself includes (1) an AC transformer, (2) an inverter to appropriately energize the generator rotor winding, (3) a DC-DC converter designed to increase the DC voltage, (4) a rectifier to pull energy from the grid primarily to drive the machine rotor winding, (5) an AC transformer to increase the output voltage, and (6) a rectifier to convert the output from AC-DC for connection to a DC collector grid.

Similarly, for a Type 4 WTG, the potential equipment includes (1) an AC transformer, (2) a rectifier, (3) a DC-DC converter designed to increase the DC voltage, (4) an inverter, (5) a post-converter AC transformer, and (6) an AC-DC rectifier.

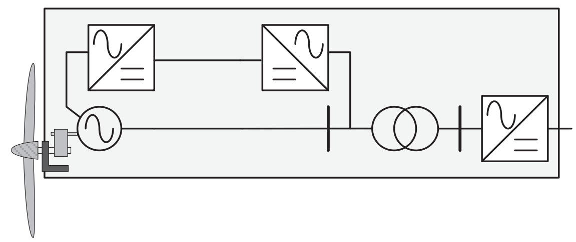
For any actual WTG design, only certain components would be required. For example, the Type 3 WTG typically excludes transformer (1), the DC-DC converter (3), and AC-DC converter (6) (see Figure 5-6 (a)), but if it were to be connected to a DC collector system, then converter (6) would be required (Figure 5-6 (b)). On the other hand, a Type 4 WTG will typically consist of only converters (2) and (4) and transformer (5) (Figure 5-6 (c)), but excluding (4) and (5) would allow connection to a DC collector system with a very simple system (Figure 5-6 (d)), and adding a DC-DC converter (3) would permit a higher DC collector system voltage (Figure 5-6 (e)).

These are only a few possible examples for the WTG options that would increase the flexibility of the design selection and operation and that could impact the cost of the WTGs themselves.

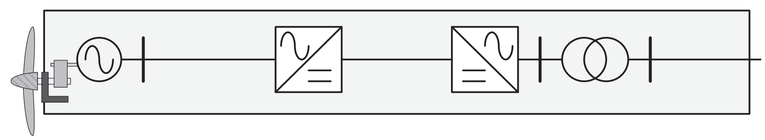
Many collection network configurations have been proposed for offshore wind farms. However, the parallel collection network and series collection network are well-defined configurations.



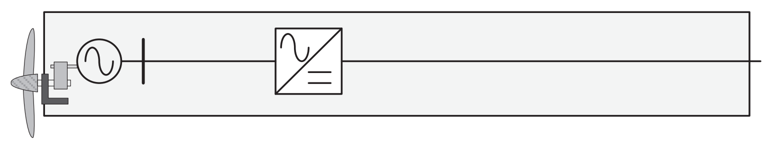
(a) Typical Type 3 (DFIG) WTG for an AC collector



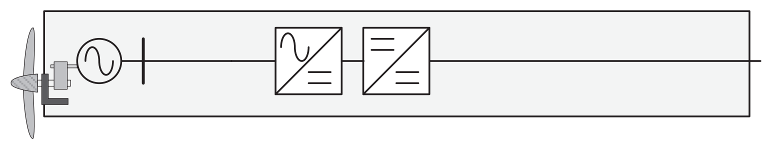
(b) Example of a Type 3 (DFIG) WTG for a DC collector



(c) Typical Type 4 WTG for an AC collector



(d) Example of a Type 4 WTG for a DC collector

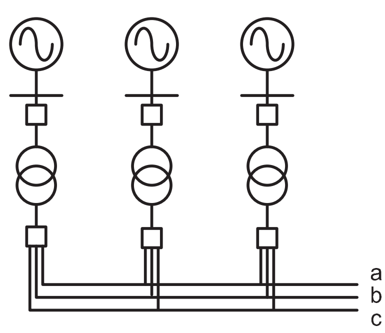


(e) Example of a Type 4 WTG with DC voltage boost for a DC collector

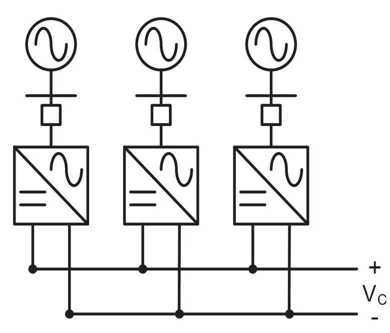
Figure 5-6. Example WTG topology options

5.3.1 PARALLEL COLLECTION NETWORK

The parallel connection network can be designed for both AC and DC offshore wind energy collection systems. Figure 5-7 illustrates the parallel connection for each.



(a) AC collector network



(b) DC collector network

Figure 5-7. Parallel collection network

In the parallel arrangement, each WTG is connected to all AC rails (three phases, Figure 5-7 (a)) or both DC rails (one positive, the other negative, Figure 5-7 (b)) that lead to the collector platform. The voltage between the rails is nominally the same at each wind turbine and matches the output of the turbine step-up transformer (AC collector system) or the output of the turbine rectifier (DC collector system). The current in the rails increases at each turbine, because each injects its power into the collector system.

Potential Topologies

Parallel collection networks can be designed with different layouts depending on the wind farm size, system efficiency, and the desired level of reliability. In general, there will be multiple strings of wind turbines, with each string connected to a central hub. This hub may be the collector substation platform itself, or it may be an intermediate platform that collects the power for a local group of turbines and then delivers the power to the main collector platform and substation.

Four basic layouts are considered below: the (1) radial configuration, (2) single-sided ring, (3) double-sided ring, and (4) star configuration.

Radial Configuration

Figure 5-8 shows an example of an offshore wind farm collection system with a radial configuration. With this type of design, wind turbines are connected to cable feeders that are radial from the hub. The maximum number of wind turbines on each feeder is determined by the maximum rating of the feeder and the wind generator capacity. The total cable length of this configuration is relatively small compared to other options, and it is possible to reduce the capacity of the cable farther from the hub. This makes the radial configuration a relatively low-cost design. Because the layout is straightforward, the collector system is simple to control.

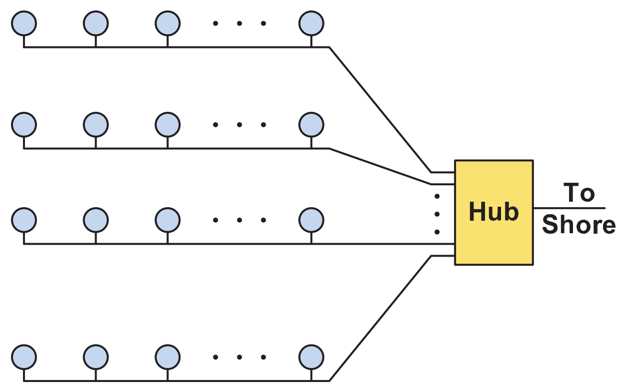


Figure 5-8. Offshore wind farm collection system with radial configuration

There are three outage levels for this type of system: (1) single WTG outage, (2) feeder outage, and (3) plant outage. A single WTG outage is triggered by the failure of any component on the wind tower. A feeder outage is triggered by the failure of any cable section or the failure of the feeder protection circuit breaker at the platform. The failure of a wind turbine circuit breaker also triggers a feeder level outage. A plant-level outage is associated with the failure of the main transformer or the bus bar. The failure of a feeder circuit breaker also triggers a plant-level outage [1]. The overall reliability of this type of design is somewhat low, because little to no redundancy is built in.

Examples of offshore wind farms for which the radial design has been adopted or proposed include the 160-MW Horns Rev in Denmark, the 640-MW Krieger's Flak in Sweden, and the 420-MW Cape Wind in the United States [2].

Single-Sided Ring Configuration

Figure 5-9 shows an example of a single-sided ring configuration. Expanding on the radial configuration, a redundant circuit runs from the last wind turbine to the hub. This additional cable must have the capacity to handle the full power generation of the group of wind turbines in case a fault happens in the primary circuit close to the hub end. Reducing the capacity of the primary cable farther from the hub is more difficult in this design, because all cable sections could potentially carry large amounts of power depending on what generation will still produce after faults.

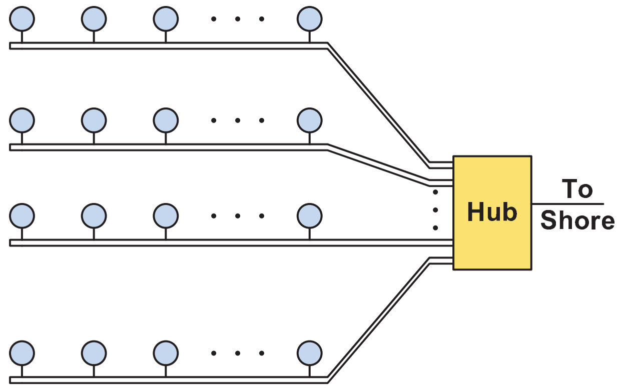


Figure 5-9 Offshore wind farm collection system with single-sided ring configuration

The redundant design provides higher collector system reliability, but capital costs increase as a result of longer cable runs and higher cable rating requirements.

An initial feasibility study commissioned by the DOWNVIND consortium recommended and utilized this design for the 1-GW wind farm collector system [2].

Double-Sided Ring Configuration

Figure 5-10 shows an example of a collection system with a double-sided ring configuration. Also expanding on the radial configuration, a redundant circuit connects the last two turbines of the two circuits. Reducing the capacity of the cable away from the hub is generally not allowed in this design. In the event of faults close to the hub, the full power generation of one circuit needs to be delivered through the other circuit, so the cable at the hub end needs to have capacity to handle the total generation of double the number of wind turbines. The upper limit of cable ratings may cause some restrictions in this regard.

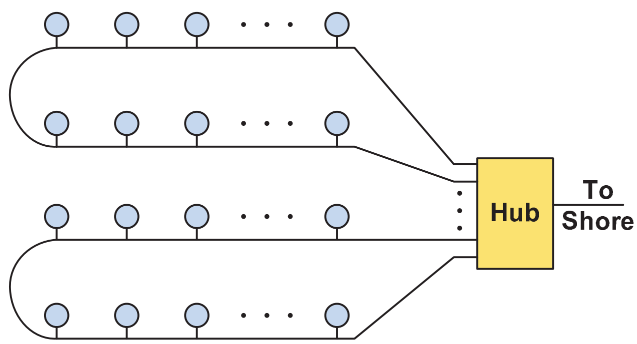


Figure 5-10 Offshore wind farm collection system with double-sided ring configuration

This design provides higher system reliability than the radial configuration and relatively lower additional capital cost compared to the single-sided ring configuration.

Most of the existing offshore wind farms have little redundancy or none at all. However, most of these wind farms are small scale (<100 MW), in which the probability of a fault and the associated costs are lower than the costs associated with additional equipment. In the case of large-scale wind farms (>100 MW), this situation may change, particularly in offshore installations where the repair downtimes are significantly longer compared to those onshore [2].

Star Configuration

Figure 5-11 shows an example of an offshore wind farm collection system with a star configuration. A typical arrangement connects each surrounding wind turbine to the center wind turbine with lower rated cables then uses a higher rated cable to connect all the wind turbines to the hub. This design could help reduce cable costs because of the lower cable ratings. Collector system reliability is improved, because one cable outage will impact only one wind turbine. The voltage regulation among wind turbines is also easier for this type of layout. The major cost implication of this arrangement is the more complex switchgear requirement at the wind turbine in the center of the star [2]. The additional cables of the star pattern may also make it difficult for maintenance vessels to anchor near the central turbine or other interior turbines without threatening the cables of the star group.

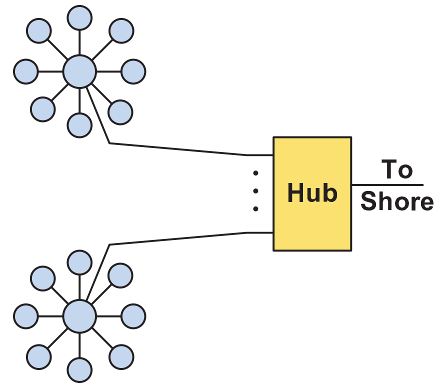


Figure 5-11 Offshore wind farm collection system with star configuration

5.3.2 SERIES COLLECTION NETWORK

A series connection could be considered for a DC offshore wind farm collection system design. Figure 5-12 illustrates this type of network.

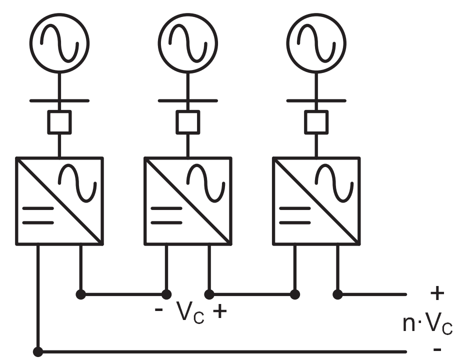


Figure 5-12 Series DC collection network

In the series arrangement, each terminal of the main DC system at the collector platform is directly connected to either the first turbine in the string or the last turbine in the string, and each turbine is connected in series (i.e. daisy-chained). The voltage across the collector rails increases with each added turbine, with the total voltage at the platform approximately equal to the converter voltage multiplied by the number of turbines in the string. Figure 5-13 shows an example of series DC collection network with an offshore platform.

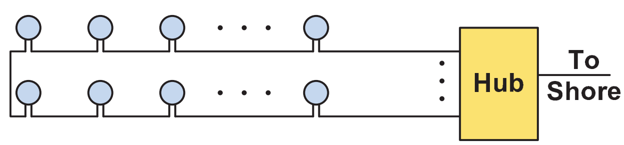


Figure 5-13 Series DC collection network with offshore platform

One potential benefit of the series-connected WTGs is that a careful selection of the number of generators will allow the collector voltage to be built to a level appropriate for direct feed into the onshore inverter system. This could completely eliminate the need for any offshore collector or delivery platforms. Multiple strings of this voltage can theoretically be connected in parallel to increase the total power shipped to shore. Figure 5-14 shows an example of series DC collection network without offshore platform.

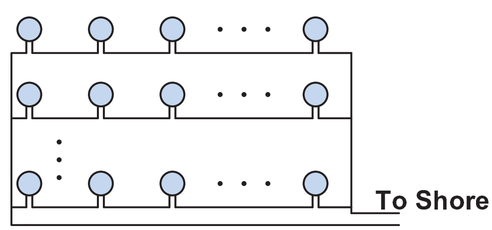
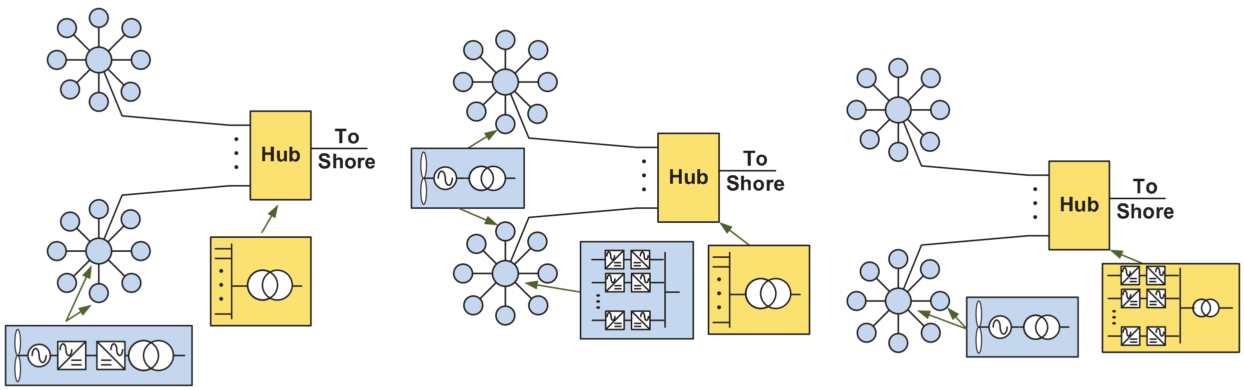


Figure 5-14 Series DC collection network without offshore platform

In practice, such arrangements are expected to be challenging for a number of reasons. In each individual string, the output power of each WTG is expected to vary, resulting in different DC voltages from each turbine and a range of operating voltages possible across the string. Further, both during build-out and during normal operation, the full number of WTGs on the string will not be on-line. This increases the range of DC voltages across each string. The design of the DC-AC converter station at the hub or onshore must account for these asymmetries in individual WTG production levels. If multiple strings are connected in parallel, the challenge would be ensure that the disparate voltages are matched closely enough to prevent large circulating currents. In addition, some appropriate means of protection and disconnection of a string in the event of a fault must be provided. In the end, this is not expected to be a practical arrangement.

Cluster Collection System Design

The cluster collection system design can be applied to each type of parallel or series collection network. Figure 5-15 shows an example of an AC parallel connection network with a star configuration.



(a) Conventional *(b) Cluster converters at wind turbines* *(c) Cluster converters at collection sub*

Figure 5-15 AC parallel connection network with star configuration

With a conventional collection system design (Figure 5-15 (a)), each WTG physical tower includes a WTG, AC/AC converter, and step-up transformer. All WTGs are connected to the platform that houses a transformer to step up the voltage for delivering to shore.

With a cluster collection system design, the converters are all collocated at either the central wind turbine platform (Figure 5-15 (b)) or at the collector substation platform (Figure 5-15 (c)). Each WTGs physical tower includes only a WTG and step-up transformer.

The failure rates of converters are higher than those of other electrical components—they are twice those of WTGs and almost an order of magnitude higher than those of circuit breakers [1]. By placing the converters at the platforms, the cluster collection system design helps to reduce repair and maintenance time, because the accessibility of the wind towers is more limited than that of the collector platforms. By reducing the repair and maintenance downtime, a cluster collection system design increases system reliability while maintaining the advantages of the parallel or series collection configurations.

5.3.3 Delivery Systems

Two options exist for delivering the wind-generated electricity to shore: high-voltage (HV) AC (HVAC) and HVDC. Each is described in this section, and more explicit, quantitative investigations of the benefits and limitations are reported in Section 6.

HV in this context is generally in the range of 110 kV to 345 kV. Although it is technically feasible to use lower voltages, the cabling and other requirements to move the power levels associated with offshore wind farms make them impractical.

HVAC Considerations

HVAC systems are used for onshore wind farms because of the normally short distances required to interconnect to the bulk transmission networks. Likewise, HVAC systems are the preferred technology for connecting offshore wind farms that are located close to shore.

The primary limitation for HVAC systems offshore is the high electrical capacitance of the AC cables. For longer lengths of cable, the capacitive charging current becomes significant, because it increases linearly with both voltage and distance. This large capacitive charging current reduces the cable's current-carrying capacity available for transferring the real power supplied by the wind farm. This distance-limiting effect of cables is discussed in more detail in Section 5.6.4.

Shunt reactors can be used to partially compensate for this cable charging. They are much easier to install onshore, where, if needed, they can be readily applied mid-route on long cable runs. In the offshore environment, however, they may be economically feasible only at the onshore end of the cable. Offshore reactors will add space and weight requirements to the platforms, which will, therefore, increase the costs. Shunt reactors applied mid-route between the collector platform and shore may not be economical, because, with current technology, they would require additional dedicated platforms. All of these considerations influence the economics for offshore HVAC systems and help to limit the distance between the platforms and the onshore station to roughly 45 mi to 60 mi (70 km to 100 km) until HVDC alternatives become more attractive economically.

HVDC Considerations

Classic HVDC systems are based on current source converter (CSC) HVDC technology, which requires a relatively strong synchronous voltage source to operate. The converter connection must also be made to a point at which the network's three-phase symmetrical short-circuit capacity is at least twice the converter rating. This ensures proper commutation (switching) between the converter's power electronic switches (thyristor valves). These criteria are not met for offshore applications at the present state of development, and additional, expensive, bulky, and heavy equipment (such as a static compensator or synchronous condenser) would be required to install classic HVDC systems on the offshore platform to provide the synchronous voltage resource.

A much better alternative is the VSC HVDC system, which does not rely on the line voltage to ensure proper switching (commutation) and can be connected to very weak or even passive system. Although these tend to experience higher converter station losses compared to CSC HVDC systems, VSC HVDC systems allow for substantially more flexible operation and are a highly effective solution for remote offshore wind power delivery.

A more detailed discussion of HVDC systems is provided in Section 5.4.

Delivery System Topology Options

Several arrangements exist for structuring the delivery system, including (1) radial connections, (2) split connections, (3) backbones, and (4) grids.

Radial Connections

A radial connection involves a single delivery path from offshore to shore. This may take the form of a direct connection from an individual wind farm to shore, or a central hub may be established where multiple wind farms feed into a single delivery path to shore (see Figure 5-16).

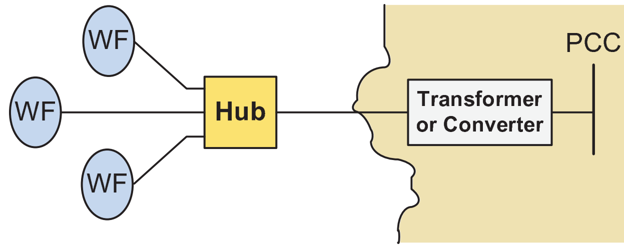


Figure 5-16. Offshore wind farm delivery system with radial connection

Split Connections

A split connection is a connection of a single wind farm or a hub to multiple onshore points (Figure 5-17). In AC systems, the power will flow as determined by the electrical impedances of the network. In DC systems, the power flow can be controlled by the converter stations.

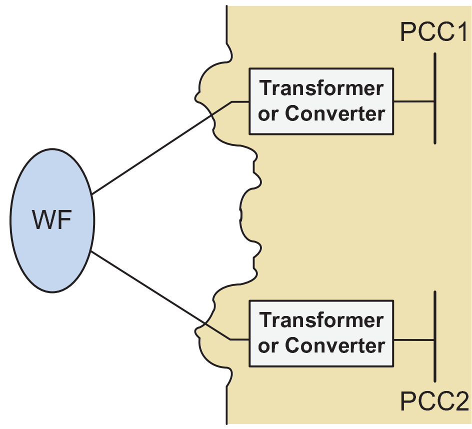


Figure 5-17. Offshore wind farm delivery system with split connection

Backbone

A backbone connection takes the form of an interconnection of multiple offshore delivery platforms in a continuous chain, such that the delivery connections at each platform form the "ribs" of the system, and the offshore interconnection form the "spine." This topology increases the reliability of the delivery system, and it is likely to be a logical development because multiple radial systems are built along a section of shoreline (Figure 5-18). The proposed Atlantic Wind Connection appears to follow this system topology. It will require careful coordination of the technologies used at each wind farm to ensure the capability to make the interconnection.

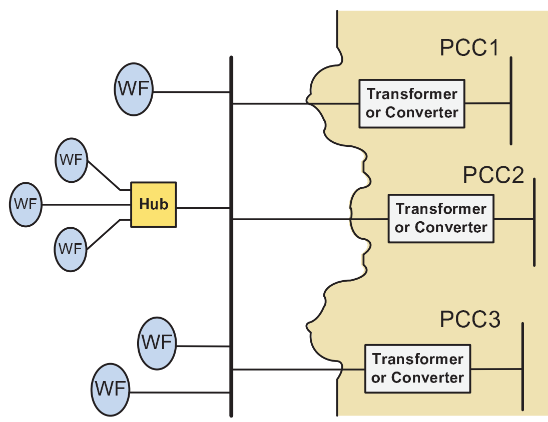


Figure 5-18. Offshore wind farm delivery system with backbone connection

For example, for HVAC systems, phase-shifting transformers could be used at the onshore stations to control the power flow and help balance the amount of power injected into each site. Phase-shifting transformers adjust the voltage angle by means of properly designed and controlled series windings and shunt windings. The speed of the phase shifter is quite slow (5 s to 10 s per tap step), however, and may take a minute or more to achieve a desired phase shift [3]. This limits its usefulness during fast dynamic events. For applications with large amounts of generation and broad network connections, phase-shifting transformers must have high power ratings and large angular range to provide more flexibility for power flow control during steady-state conditions. Such transformers are expected to be quite expensive.

Much faster dynamic response can be achieved using a multi-terminal HVDC system. In this case, industry standards are necessary to ensure that the equipment from multiple manufacturers can coordinate and operate well together. The converters add significant cost to these systems. Some efforts are currently underway to evaluate the necessary standards.

<u>*Offshore Grid*</u>

An offshore grid connection would involve the interconnection of multiple farms or hubs offshore and provide multiple connections onshore. Technically, a backbone would be a form of offshore grid; however, more complex interconnections among the delivery platforms are contemplated in this case (Figure 5-19).

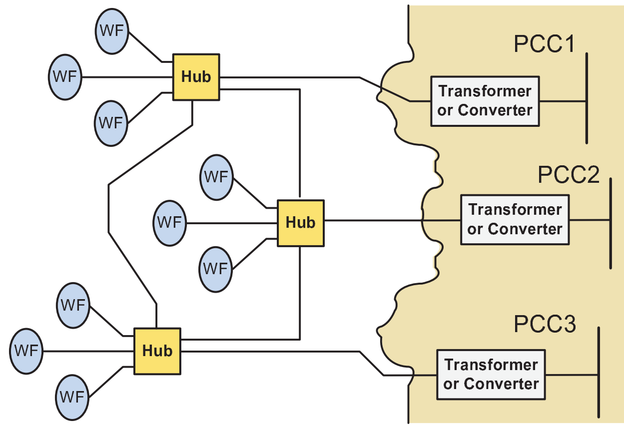


Figure 5-19. Offshore wind farm delivery system with offshore grid

The optimal connection at any given site or area will depend on several factors, such as whether more than one farm is planned in close proximity to each other, the distance of the wind farm to shore, and the electricity market situation between the different regions.

Hub connections will be more economically attractive for wind farms that are planned close to each other and far from shore. Offshore hubs are expected to help mitigate the environmental impacts and societal objections to laying the higher number of cables that would be required for individual farms.

Compared to radial connections, offshore grids have the potential to provide benefits to multiple regions. Offshore grids are expected to allow for the delivery of large-scale offshore wind power to the load centers where it is most needed onshore while bypassing onshore transmission system bottlenecks. This type of connection may also develop more interconnections between regions to relieve onshore transmission congestion. By connecting wind farms in geographically diverse locations, the spatial smoothing effects of wind power are expected to help reduce wind power variability.

Although offshore grids could be developed using either AC or DC technology, they are expected to cross multiple regions and require long-distance cable connections. HVDC systems then become the probable technology. More precisely, multi-terminal HVDC systems are necessary to realize an offshore grid. Section 5.5 below discusses various HVDC technologies that could be used for these grids, and although no multi-terminal systems have been built using the technologies best suited for offshore grids, manufacturers are confident that such systems can be built within the next few years.

At least two different types of HVDC grids can be identified:

- Regional HVDC grid—This is a multi-terminal HVDC system that consists of one protection zone for DC ground faults. It is fully possible to build a regional HVDC grid today using proven technology. HVDC breakers are not needed for regional HVDC grids. A fault on the DC side would be cleared using the AC breakers on the AC side to trip the whole HVDC system, and the portions of the DC system that are free from faults could then be rapidly restarted. The temporary loss of the entire regional HVDC system would have limited impact on the overall power system. This type of HVDC grid is normally in radial or star network configurations, and the power rating of the grid is limited.

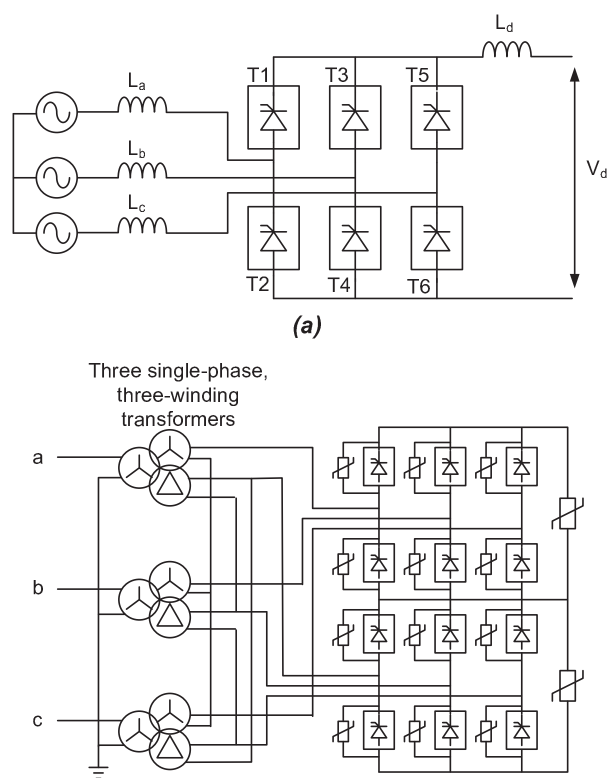
- Interregional HVDC grids—This is a multi-terminal HVDC system that needs multiple protection zones for DC ground faults. Interregional HVDC grids will require the use of HVDC breakers, fast protections and control schemes, and HV DC-DC converters for connecting different regional systems. Although some manufacturers may be able to provide HVDC breakers today, continuing development is needed along with proper standards among the manufacturers to support the technology developments and encourage the confidence to invest in multi-terminal HVDC systems. Regulatory issues, such as how to coordinate the operation of the new grids among different regions, also need to be solved.

5.4 HVDC Converters

The use of HVDC transmission is continuing to become more and more prevalent in the U.S. electric grid infrastructure, because it often provides significant benefits compared to HVAC. In this section, use of HVDC for the transmission of renewable resources, notably offshore wind, is discussed. At the commercial level, two primary types of converters change between HVAC and HVDC: (1) line-commutated converters (LCCs) and (2) VSCs. The LCC technology is not generally applicable to offshore wind delivery, but a brief overview is presented for completeness and comparison. The emphasis is placed on the VSC, because it is more suitable for use in integrating renewable offshore wind. A large amount of research effort has been invested in VSC technologies for such integration.

5.4.1 LCC

LCC technology has been used commercially for long-distance transmission since the 1950s [4]. The switching elements for LCC topologies were originally mercury-arc valves, but thyristors have been used in installations built since they were developed. These devices allow for some control of the DC voltage in that they can be turned on at selected instances with a proper AC voltage across them. They cannot, however, be turned off at will. Because of this limitation, LCCs are best suited for the bulk transmission of power when the likelihood of a strong, operational grid at both terminals is very high and the switching elements act as intended with no commutation failures. In a weaker AC system, such as an offshore wind farm, the switching elements may not switch as intended, and the output waveforms will not be as desired.



(a)

(b)

Figure 5-20. (a) Six-pulse thyristor circuit, (b) Twelve-pulse thyristor circuit

Circuit topologies for LCCs are either six-pulse or twelve-pulse configurations, as illustrated in Figure 5-20. The ideal DC outputs are shown in Figure 5-21. As shown, the waveforms are not perfectly constant, but they contain a certain amount of ripple that requires filtering to provide the desired DC value. The primary filtering is accomplished with a large inductance to smooth the DC current so that it is practically constant. The twelve-pulse bridge is essentially two six-pulse bridges combined together. A benefit is gained when the top six elements have the same configuration as the standalone six-pulse bridge, and the bottom six elements are fed by a transformer with a 30-degree phase shift of the source voltage. The DC voltage waveforms have a peak every 30 degrees in the twelve-pulse configuration compared to every 60 degrees in the six-pulse version, which results in less ripples. In other words, a comparison of the waveforms in Figure 5-21 shows that the average value of the twelve-pulse output has less deviation from 1 p.u. and therefore requires less filtering to achieve a constant DC output.

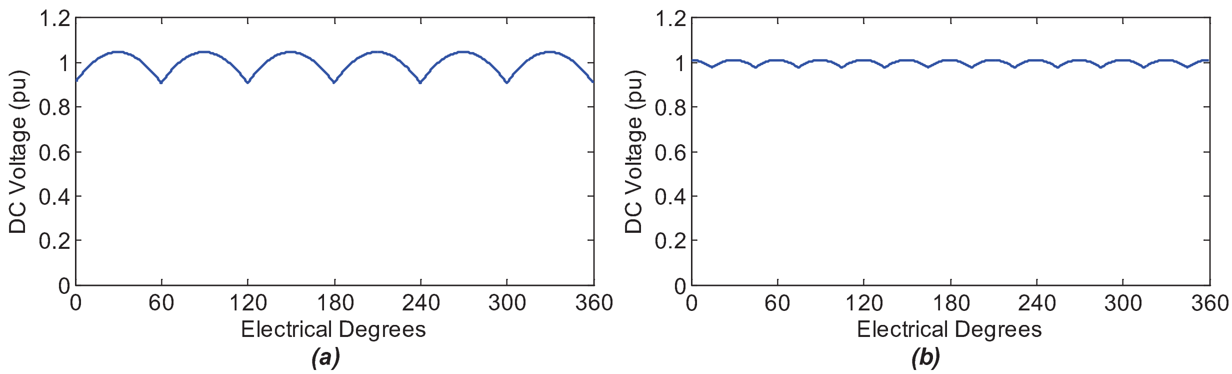


Figure 5-21. (a) Idealized voltage across DC terminals of a six-pulse bridge and (b) idealized voltage across DC terminals of a twelve-pulse bridge

5.4.2 VSC

VSC technology differs from LCC technology primarily by the use of switching elements that are able to be turned both on and off. This capability gives the VSC many benefits that can be exploited for use in offshore wind systems. One common switching device used in VSCs is the insulated-gate bipolar transistor (IGBT). Switches like the IGBT can be used to create a number of different converter topologies, each with its own characteristics.

Two- and Three-level VSCs

The earliest VSCs were two- and three-level VSCs. The names are derived from the number of distinct voltage levels utilized to convert between DC and AC voltages. Although these are used less frequently today, they are discussed here to provide a foundation for discussing how more advanced converters solve various shortcomings and provide additional benefits.

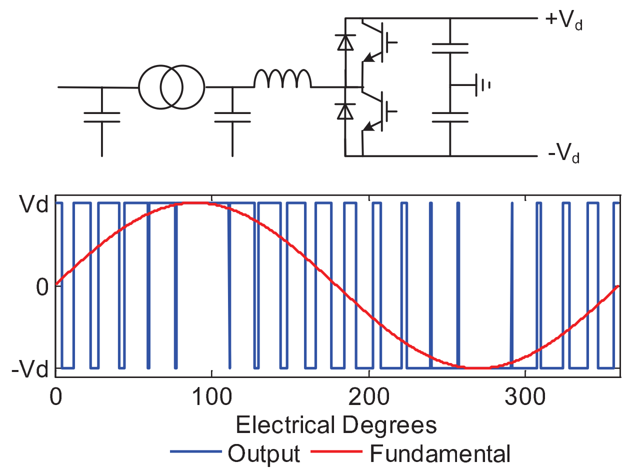


Figure 5-22. Two-level single-phase VSC circuit configuration and output waveform

The circuit layout of a two-level VSC is shown in Figure 5-22 [5]. The name indicates that the AC terminal—the diode side connection of the inductor in the figure—can be connected to only two DC voltage levels. These two voltage levels are obtained by applying a DC voltage across the two switches from the right side of the circuit. The switches are then turned on and off according to a pulse-width modulation control scheme. Because the power electronic switches conduct in only one direction, antiparallel diodes are placed across the main switches of the polarity set to allow conduction in the opposite direction. This switching scheme results in either a positive DC voltage or equal-amplitude negative DC voltage at the output.

The technique is straightforward to implement, but it has a few shortcomings. The output voltage waveform is also shown in Figure 5-22 and resembles a square-wave of varying widths. This waveform consists of a large number of harmonics of the fundamental AC frequency (e.g., 60 Hz) that must be filtered out to prevent excessive harmonics from being injected into the power grid.

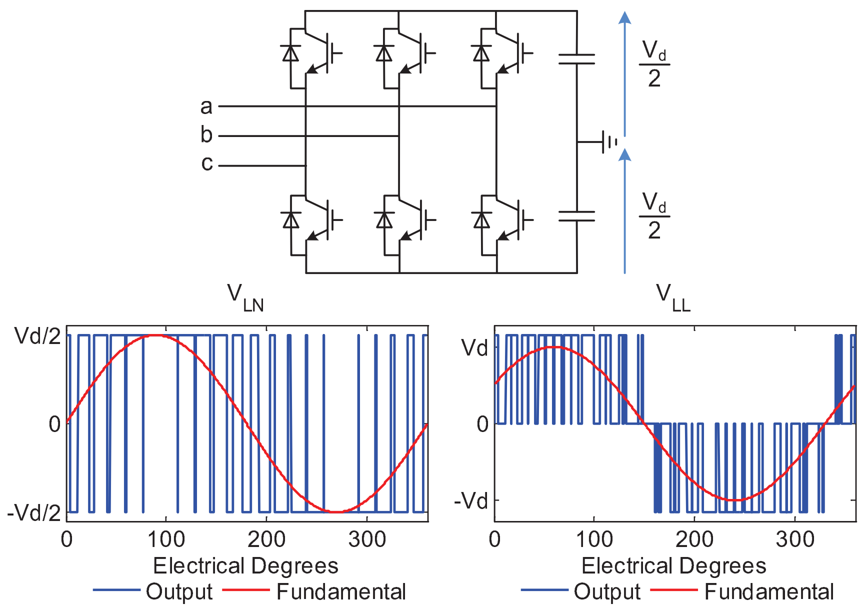


Figure 5-23. Three-phase, two-level VSC

A three-phase version of the two-level VSC circuit is shown in Figure 5-23 (see [6]). If these circuits are taken as literal interpretations of an actual implementation, it would be necessary for the two switches of each phase to be capable of handling half of the source voltage. In an HV utility application, this means that the voltage rating would be on the order of tens or hundreds of kilovolts. If a switch were available to fit this necessary voltage rating, it would be very costly; however, such devices have not proven practical to implement. One approach to remedy this is to place many switches with reasonable voltage ratings in series with the total string capable of handling the ultimate desired rating [7].

Placing many switches in series requires that each switch conduct simultaneously, otherwise the voltage stresses will vary between switches and damage may occur to those with this highest stresses. In addition, the current flow could be inconsistent. Each switch also requires a snubber circuit, which consists of elements (e.g., resistor, capacitor) connected in parallel to the switch to damp electrical transients that could damage the switching element during operation. Snubber circuits themselves add to the bulk of the overall circuit and add power losses. [7]

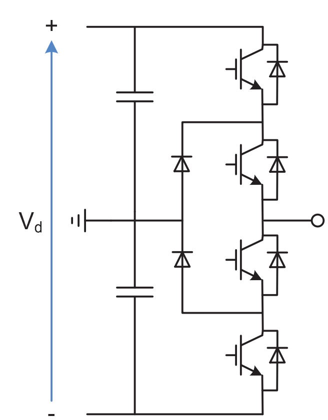


Figure 5-24. One leg of a three-level neutral-point clamped (NPC) converter

To remedy some of the issues presented with the two-level VSC circuit design—particularly high levels of harmonics—the three-level neutral-point-clamped (NPC) converter was created. A circuit diagram for a single phase of this converter structure is shown in Figure 5-24. The circuit is made of two half-bridge converters as well as two clamp diodes identified in Figure 5-24. These diodes connect specific nodes of the circuit to a neutral voltage point, giving rise to the NPC name. For a three-phase configuration, an identical single-phase circuit configuration is used for each phase leg. The complete topology is shown in Figure 5-25.

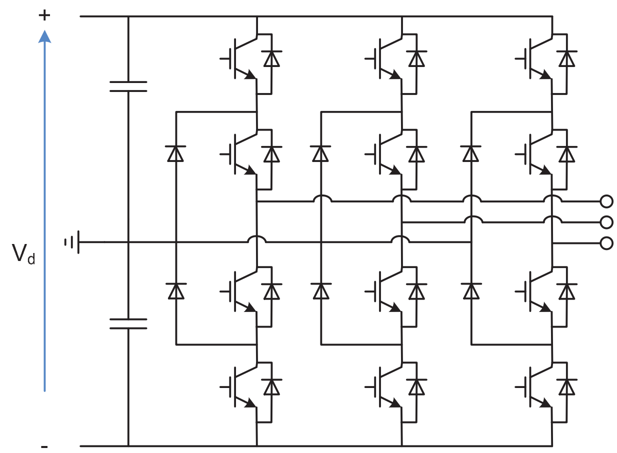


Figure 5-25. Three-phase, three-level NPC circuit diagram

As the name implies, a three-level NPC converter has a third voltage level (neutral) to which the AC terminal can be connected. This is shown in Figure 5-26 [7]. Rather than switching directly between plus and minus half the DC voltage input, the converter is able to switch to a zero voltage level as well. This simulates a sinusoidal waveform more accurately than the two-level converter and results in fewer harmonics and smaller filters. The harmonics are present in even multiples of the frequency modulation index m_f. This index is simply the ratio of the switching frequency (or carrier frequency) divided by the fundamental frequency. If the fundamental frequency is kept constant, then increasing the switching frequency pushes the harmonics farther away from the desired fundamental frequency, allowing for more economical filters. However, the increased switching frequency results in increased switching losses; thus, it is necessary to find a balance between the harmonics and filtering and the losses.

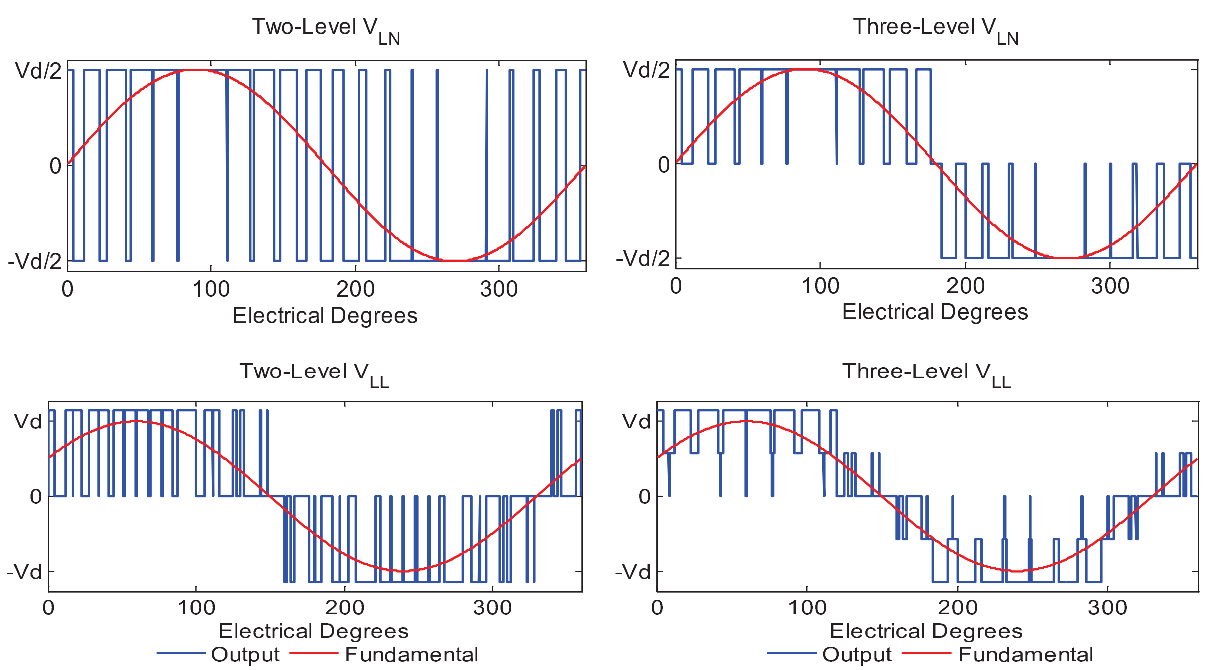


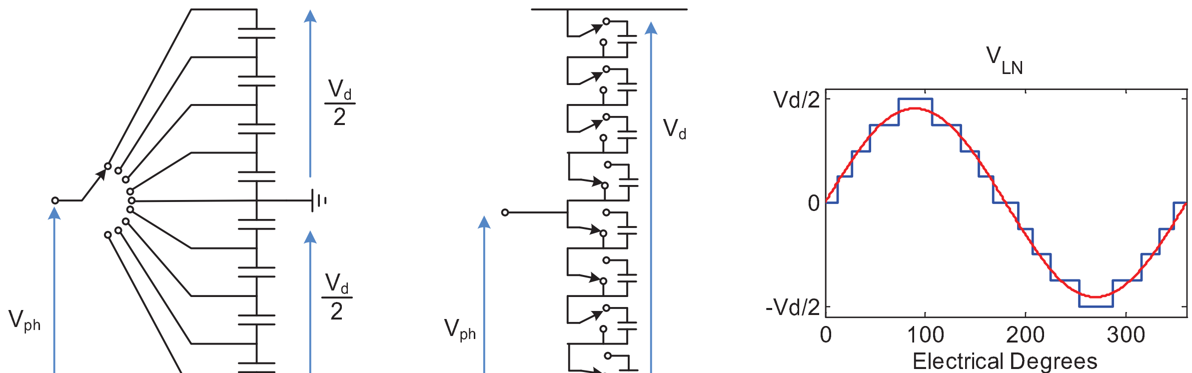
Figure 5-26. Voltage output of two-level (left) and three-level (right) NPC converters; line-to-neutral voltages (top); and line-to-line voltages (bottom)

Multi-Level Converters

Although relatively simple, the primary limitations of the two-level and three-level converters are the potential for HV stresses on the power electronic switches, high harmonic content requiring relatively large filters and switching losses. The issues can be mitigated to a large extent by increasing the number of levels utilized in the converters. Many variations of multi-level converters are available, but three types are generally utilized by the prominent VSC vendors in the electric power industry: (1) modular multi-level (MMC) converters, (2) cascaded two-level (CTL) converters, and (3) alternative arm modular (AAM) converters. Three major vendors are present in the offshore wind market (ABB, Alstom, and Siemens), and each has their own preferences for VSC design. Each of these is outlined below, with emphasis on their basic concepts and benefits.

MMCs

The goal of a MMC is to increase the number of levels (more than three) while keeping the circuitry and control from becoming too complex or unwieldy. With the NPC concept discussed above, it is possible to have as many levels as desired, but a point of diminishing returns will eventually be reached. The circuit layout for an *n*-level NPC topology is fairly straightforward, but the control system becomes very involved because of the need to maintain voltage balance between all of the required capacitors. Therefore, a new topology, the MMC was created.



(a) Operational concept ***(b) Implementation concept*** ***(c) Single-phase output***

Figure 5-27. MMC approach

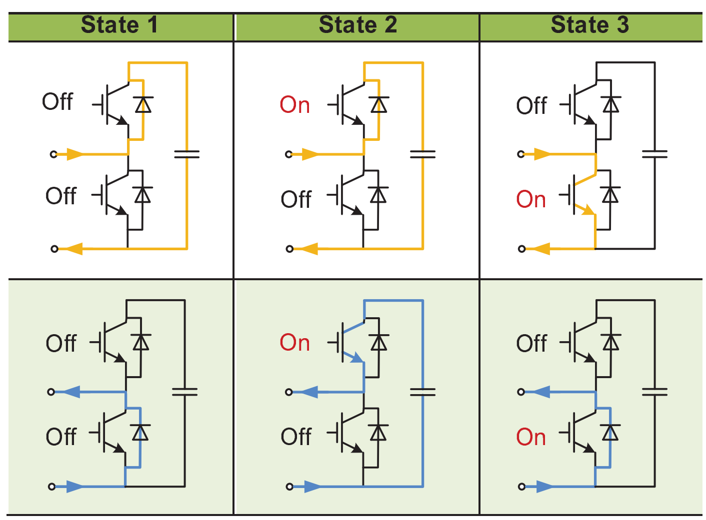


Figure 5-28. Different switching states and their corresponding current flow

The concept and typical output of the MMC are shown in Figure 5-27 [6]. The conceptual operation of one phase leg is illustrated in Figure 5-27 (a), and the implementation concept is illustrated in Figure 5-27 (b). The essential operating principle is to divide total voltage across a number of different sub-modules (four in each direction in Figure 5-27 (b)), with each providing a step in the output waveform as shown in Figure 5-27 (c). This is accomplished by charging a capacitor within each sub-module so that it can act as a controllable, independent source. Switching a module capacitor into the circuit will cause its voltage to add to the output voltage. By placing sub-modules in series, the desired output AC waveform can be obtained. The circuit layout of the sub-module is a so-called half-bridge configuration, as shown in Figure 5-28. This consists of two IGBT switching elements and a DC capacitor for energy storage. The two switches allow for the capacitor to be placed in and out of the circuit, depending on the voltage desired and dictated by the control system.

The controlled switching of the modules allows for the staircase-like waveform that synthesizes a sinusoid. This output compared to a sine wave is shown in Figure 5-27 (c). As shown in the figure, the output waveform is much closer to the desired sinusoidal output that that of the two- and three-level converters. This output requires much less filtering. In fact, if sufficient levels are used, it may be possible to completely eliminate filters and still provide acceptably low levels of harmonics.

Three different switching states are associated with a half-bridge configured sub-module [9]. These states dictate the flow of current and whether the capacitor is being charged or discharged. The three different states are shown in Figure 5-28. State 1 is a blocking state, because both switches are off. This state would be used if a fault occurred in the system, for example. During normal operation, this state is not utilized. If current is flowing from the positive DC terminal to the AC terminal (as shown in the top box beneath State 1 in Figure 5-28), the capacitor is charging through the diode D1. In the opposite current direction, the capacitor is bypassed via the diode D2. State 2, with IGBT1 switched ON and IGBT2 switched OFF, results in the voltage across the capacitor being present at the terminals of the sub-module regardless of the direction of the current flow. In one current direction (from DC positive to AC terminal, top box) the capacitor is charging through diode D1, and in the opposite current direction the capacitor is discharging through IGBT1. The last state, State 3, has IGBT2 switched ON and IGBT1 switched OFF. The capacitor is isolated with zero voltage present across the terminals of the sub-module.

A benefit to having individually controllable sub-modules is that redundant sub-modules can be placed in series to act as standby units if another unit malfunctions. These extra sub-modules are kept in State 3 until needed, so they contribute no voltage to the output. In a situation in which an operational sub-module is lost, the defective sub-module can be bypassed by a high-speed bypass switch. This approach allows for the uninterrupted flow of power, because the control system will handle the bypassing of the sub-module and in turn begin to utilize the one in standby. [6]

One issue that arises when using capacitors as voltage source elements is the need to keep them at a constant voltage level. If the voltage is maintained on one of the capacitors within a sub-module, then the output voltage will not be what is expected, and it may have an undesired effect. To prevent the voltage from drifting too far from the desired value, the voltage across the capacitor is monitored and fed back to the central control system. The half-bridge configuration allows current to travel in both directions through the capacitor, in turn allowing the capacitors to be charged or discharged as needed to maintain a steady voltage. A reactor is placed in each individual converter arm of the MMC, and it provides the dual benefit of limiting the current between the different modules as well as preventing both internal and external fault currents from becoming too large.

CTLs

Another option for a multi-level converters is a CTL converter. The CTL converter topology resembles that of an MMC. In [10], a different name was chosen to highlight that press-pack IGBTs comprise the valves. As shown in Figure 5-29, a capacitor and two valves comprised each cell, and two IGBTs and two diodes comprise each valve. Multiple cells are connected in series and function in a staggered operation.

The uniform topology of the cells in the cascaded two-level design allow for easy manufacturing. A three-dimensional model of a CTL valve arm and its corresponding circuit diagram are shown in Figure 5-30 [11]. The AC and DC output waveforms are shown in Figure 5-31 [10]. Details of the switching devices, control system, and loss mitigation can be found in [12], [13] and [13].

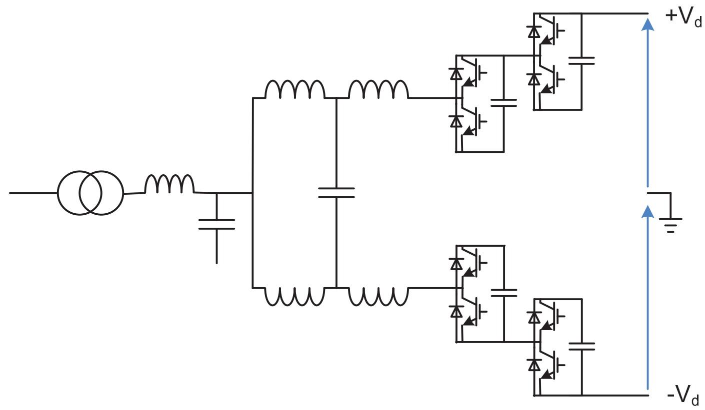


Figure 5-29. Single-line diagram of a CTL-based converter

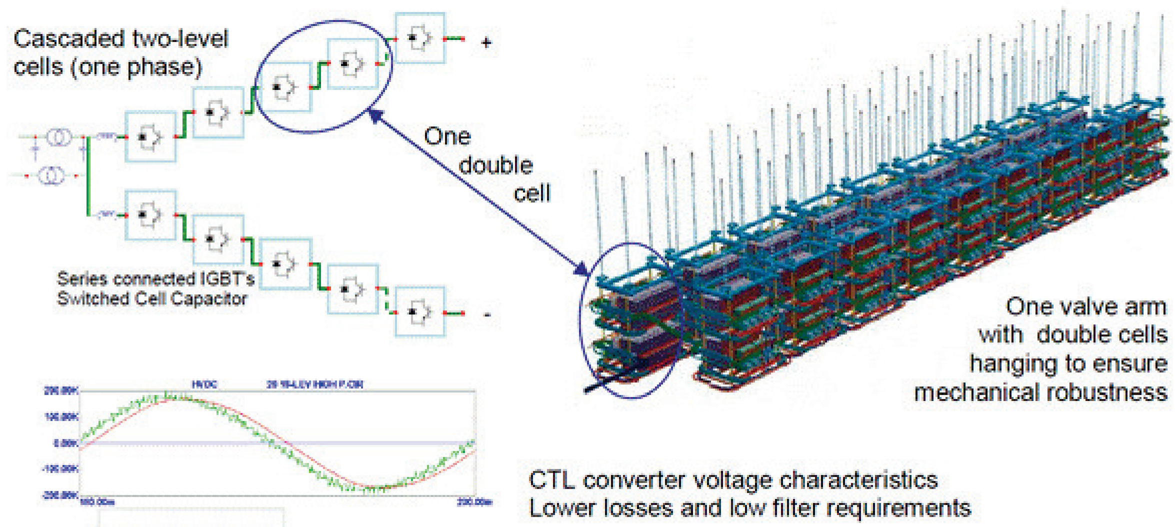


Figure 5-30. Valve arms with cascaded two-level cells (upper left). The right shows the three-dimensional model of the mechanical design. The lower left graph shows the AC voltage characteristics.

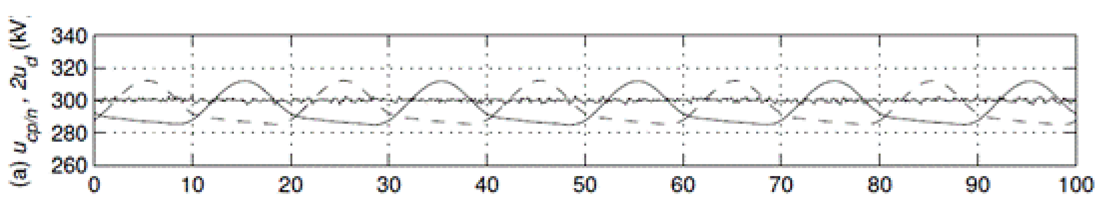


Figure 5-31. Sum of the cell voltages for positive (solid) and negative (dashed) as well as two times the mean direct voltage (which is noisy because of the switching harmonics). Courtesy of ABB.

Alternative Arm Modular Converter

A third established topology for VSC converters, an AAM converter, is a hybrid of traditional current-source converters and multi-level converters. It has the advantages of half-bridge multi-level converters in terms of low losses, low distortion, and the DC-side fault-blocking capability of full H-bridge converters [15]. Rather than using *n* two-switch or H-bridge cells in series as in the other multilevel converters, the AAM consists of *n/2* cells per arm while still being able to create *2n + 1* voltage levels per phase. This is accomplished by placing switches in series with the H-bridge cells that have bidirectional-current capability. These switches are used to block the full DC voltage during half of the operating period, thereby reducing switching losses. A circuit diagram and example output is shown in Figure 5-32 and Figure 5-33, respectively.

With this topology in steady state, the combined-series switches and H-bridge cells each experience half of the DC voltage, with the separate H-bridge capacitor and switching devices experiencing *1/(2n)* of the DC voltage. Like the other multi-level converters, an AAM can be operated by popular control techniques, such as carrier-based pulse-width modulation or space-vector modulation. [16]

One of the key features and reasons for the hybrid topology of the AAM is its ability to block DC-side currents and isolate faults. At the time of its development, no DC breaker technology was available, and another method was developed to accomplish the isolation of faults and reduce the vulnerability of the VSC. In an AAM converter, this fault isolation is possible with the inclusion of the series-connected switching devices shown at the top and bottom of each phase in Figure 5-32 [17]. These switches are rated to block the full DC link voltage and prevent any flow of active or reactive power through the converter and its switching elements. This added feature allows the converter to have DC fault ride-through capability with the ability to recover quickly and limit impact on the connected AC grid. During such fault situations, the converter switches have a reduced failure risk, thereby lowering the concern for quick replacement of failed switching elements or having to remove the entire converter from operation. The capacitor voltages in each of the cells are also kept constant and do not experience any large deviations or instabilities.

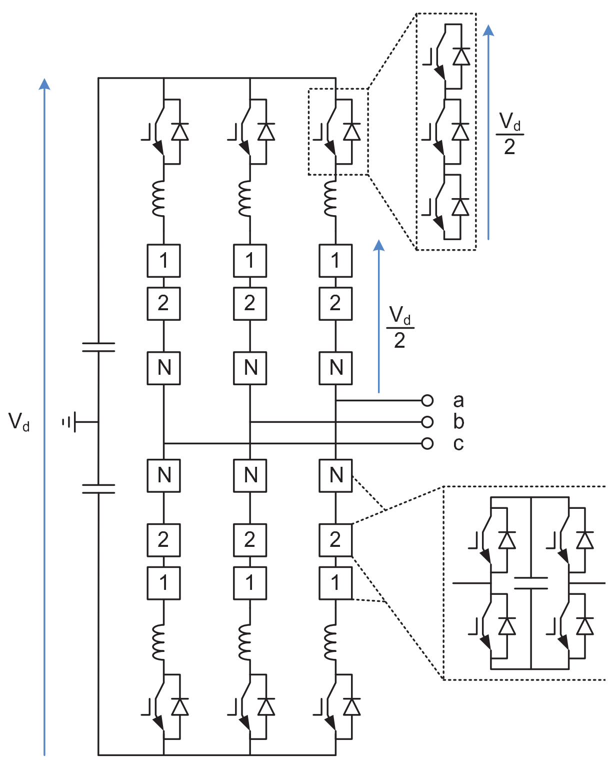


Figure 5-32. A series hybrid circuit, also known as an AAM converter

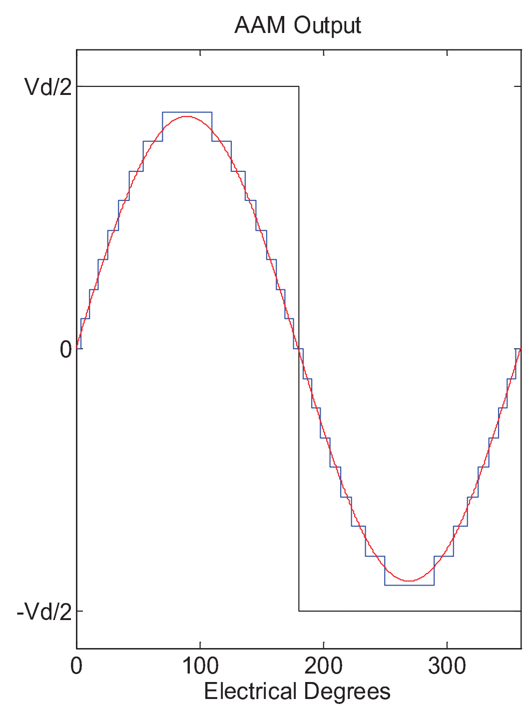


Figure 5-33. Output waveform of an AAM converter

5.4.3 *Observations About HVDC Converters*

The VSC topologies discussed above (CTL, MMC, and AAM) are all highly capable and suitable for offshore wind applications. Their footprints are smaller than that of classic LCC implementations. Their modular nature and nearly sinusoidal output permit the space requirements for filters to be reduced or eliminated. In addition, the commutation of the switching elements is not dependent on grid strength, making them well suited to the delivery of offshore wind power. In fact, in a situation such as when they are connected to offshore wind power plants, the converter connected to the offshore grid can help provide black-start capability to that grid. The topologies also possess the ability to control both active and reactive power. This is useful for riding through and recovering from faults.

Ultimately, the three different VSC topologies presented are very similar in structure and concept, and although there is variation among them, the differences are not radical. They all have almost identical features that are useful for integration into the electrical grid. Differences are more likely to arise from the various control schemes that are available for each topology, although the more popular schemes, such as carrier-based pulse-width modulation, are applicable to all three converter types. The exact implementation will depend on the application of the VSC and its performance requirements. Control schemes may be adjusted for offshore applications by the suppliers, depending on project specifics.

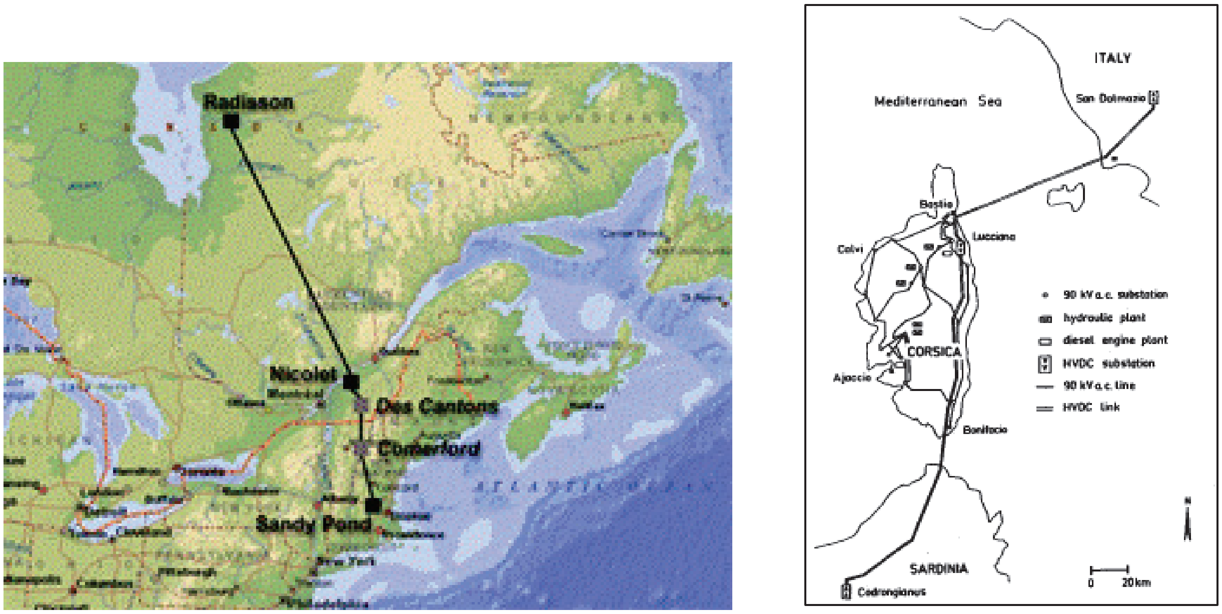
Also, noted that at present all HVDC converter technologies are air-insulated. In the marine environment, this requires converters to be housed in an enclosed room of the offshore platform. At transmission voltage levels, this requires a significant amount of space between converter phases and among the converter components and the building walls and ceilings. The large volume required for housing the HVDC converters adds tremendous weight and cost to the offshore platforms. A potential solution that the vendors could explore, possibly with the support of DOE and other research institutions, is the development of gas-insulated HVDC converter systems. This would allow for the removal of considerable volume from the HVDC offshore platforms. Although the total weight of the converter itself might increase as a result of the Gas Insulated Substation housing, the volume reduction of the platform may decrease the overall platform weight and cost.

5.5 Multi-Terminal HVDC Systems

The concept of a multi-terminal HV direct current (MTDC) system involves expanding the point-to-point setup of a typical HVDC line to include three or more terminals. In other words, instead of limiting the power transfer through the HVDC system between locations A and B, the options for delivering electricity would include locations A, B, C, D, etc. Taps from the lines connecting two points could also be expanded to another HVDC converter. A DC grid architecture results when this is done multiple times at different locations. MTDC is conceptually straightforward, but its implementation comes with a unique set of challenges.

5.5.1 *Existing MTDC Systems*

As of 2014, only two MTDC systems are in existence, with the remaining HVDC lines being point to point. These two are the Quebec–New England Transmission line [18] and the Sardinia-Corsica-Italy system [19] (see Figure 5-34). Many HVDC experts do not consider the Sardinia-Corsica-Italy a true multi-terminal HVDC system because the terminals are not operated in parallel like the Quebec-New England system. These systems are conceptually similar to a backbone structure, but, as discussed in Section 5.3.3, they are very different from a grid structure, which is considered for offshore networks. Note that neither of these system use VSC technologies that are suited to offshore networks.



(a) ***Quebec–New England [18]*** (b) ***Sardinia-Corsica-Italy [19]***

Figure 5-34. Existing MTDC lines

5.5.2 MTDC Applications

With the maturing of DC technology, the option to utilize a DC grid for some applications may be more attractive than the typical AC layout. MTDC is a key component to making a DC grid a reality and provide the means to transfer large amounts of power across a wide area while having robust interconnections among many locations. Such a system would have the advantages of point-to-point HVDC as well as the benefits that come from having an intermeshed network. However, considering MTDC applications raises topics such as controllability, topology, protection, and communication, each of which requires further investigation [20]. A deeper understanding and development of common practices in these areas would help produce more modular designs of MTDC similar to that of AC systems or point-to-point HVDC, while allowing the interconnection and coordination of equipment from multiple manufacturers.

A presentation by ABB at the IEEE Electric Power and Energy Conference 2011 entitled "Developments in Multiterminal HVDC" discussed the drivers, building blocks (cables, offshore), examples, grid-enabled HVDC, and LCC-MTDC [21]. Key driving factors were cost savings, decreased conversion losses, and enhanced reliability and functionality. Locations across Europe that have strong renewable potential in hydro, wind, and solar (see Figure 5-35) were identified. Although the potential for renewable generation is strong is these areas, the most effective way of connecting them together and/or carrying power to load centers must be found to maximize their potential.

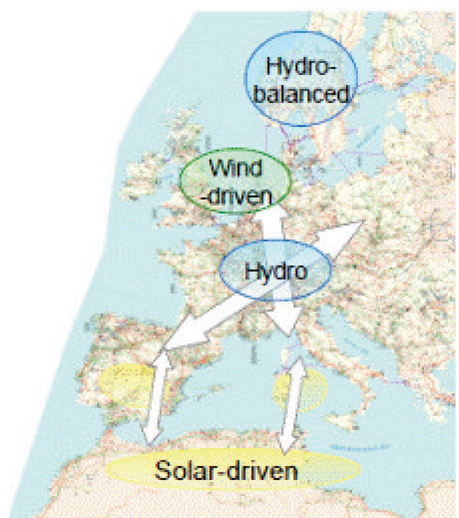


Figure 5-35. Locations with strong potential in renewable generation (Illustration by ABB)

Similar examples can be found in the United States where there is a need for new transmission to expand the integration of remote renewable generation. The widespread application of large offshore wind power plants would create another opportunity for this. However, in many cases, there is or is expected to be strong opposition to many aspects of the systems.

For example, any portions of the system that are on land that use overhead transmission lines face opposition because of their visual impacts, concerns about electromagnetic fields, and rights of way. These and other concerns can result in extensive permitting delays. DC solutions have the potential to address some of these concerns. In particular, where underground HVDC cables can be used, permitting is often simpler, because there are no visible overhead lines and it may be possible to share already existing rights of way (e.g., railway), which ease many permitting and environmental issues.

Underground cables have many advantages to overhead lines, including, but not limited to, no visual impact, no ground current, no audible noise, no relevant electromagnetic fields, better protection, and potentially easier permitting [22]. Disadvantages include higher cost, greater difficulty to access them for repairs, and difficulty verifying faults and fault locations.

5.5.3 ACADEMIC RESEARCH

Academia has provided significant research into MTDC systems (see, for example [23]-[46]). Unfortunately, because only a couple of MTDC installations currently exist, no definitive conclusions can be made regarding the performance of any control methods or designs developed in academia. One early publication from 1981 outlined two control methods that were based on control techniques for two-terminal HVDC connections [23]. These methods were developed before the advantages brought by IGBTs and VSCs in HVDC applications [40]. With these newer devices, the control methods changed because of the possibility for direct control of real and reactive power. There is a high potential for more sophisticated controls to be implemented, making the grid more robust and less prone to faults. Many papers focus on this, but this is discussed in detail in this report.

With the introduction of a DC circuit breaker from ABB [41], some academic papers that focused on DC fault protection may no longer be applicable. This is not to say that the papers are completely irrelevant, but with the continuing advancement of technology, new opportunities and methods arise for handling certain situations on the electric grid. The techniques discussed in [42] involve using fast DC switches, which are defined in the paper as mechanical switches that cannot break fault current on their own but can isolate the faulted transmission line after the fault current has been extinguished. If a DC circuit breaker is implemented rather than the fast DC switches mentioned, the protection method will be more effective, because it will not only isolate the fault but now has the capability of breaking the DC fault current.

Two interesting ideas from academia propose the use of MTDCs to supply power to urban environments [43] as well as to a premium power park [44]. Making these types of environments one terminal of an offshore grid has some significant features that are socially attractive.

The main concept proposed with using an MTDC in an urban setting is to have bulk power delivered from traditional HVDC methods (such as a current-source converter), because it is very likely that the feeds coming into the city will be part of a strong network. Tapping from the main line would be via VSC connections that would deliver power to various parts of the city. The cabling for power delivery would be underground, which fits with what is typically used in urban settings, because overhead lines are impractical [43].

The other concept involves “premium quality power parks” and focuses on the necessity of providing uninterrupted power to certain industries and businesses, for example, to banks, financial institutions, hospitals, secure government facilities, and highly automated manufacturing. Down times can create significant problems and cause these types of businesses to lose a large amount of money. Power delivery of the utmost reliability is, therefore, essential. A combination of VSCs that comprise an MTDC network would act similarly to active power filters. This configuration would be expected to handle all of the typical power quality issues, such as voltage dip, voltage swell, transients, harmonics, flicker, voltage imbalance, frequency deviation, transient interruption, and outages [44].

The concept of using an MTDC to connect and transmit offshore wind is also prevalent in the academic papers. One example is found in [45], which proposes the method shown in Figure 5-36, where two wind farms and two grid connections are shown. It is noted, however, that any number of wind farms or grid connections can be used in this configuration.

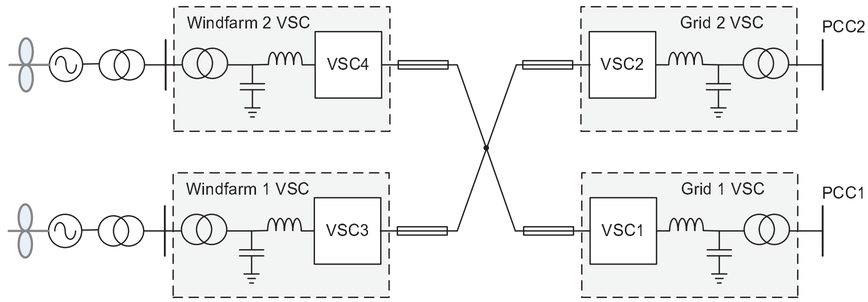


Figure 5-36. Conceptual MTDC configuration for the integration of offshore wind power

The single connection point in the middle can be changed to other configurations as well and not be limited to the single point shown. The physical distances among the different wind farms and grid connections can vary as well, and they may not be in close proximity to each other. Each wind farm and grid connection has an associated VSC that handles the necessary power conversions. The wind farm VSCs control the AC voltage and frequency at the AC connection; whereas the grid VSCs provide reactive power or AC voltage support to the grid to which they are connected.

Another paper [46] proposes a configuration that does not use VSC technology and instead opts for current source inverters in series with one another to build up a DC voltage that is suitable for transmission. Figure 5-37 shows the suggested one-line diagram of this configuration. Note that because current-source converters must be connected to a system with strong short-circuit strength, permanent magnet synchronous generators are required at the wind farms.

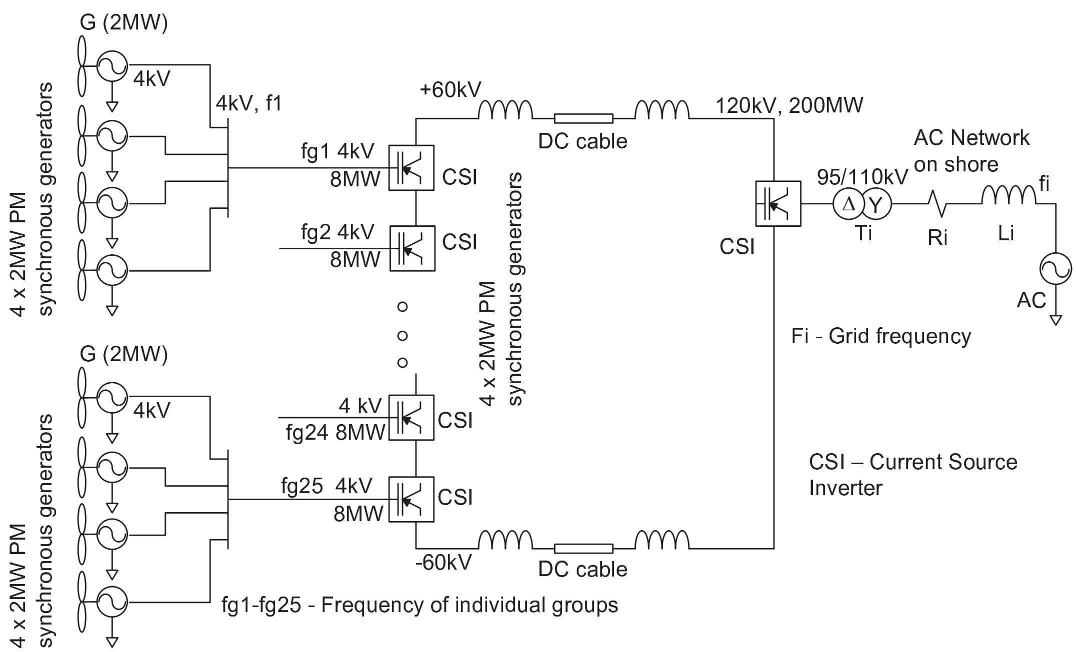


Figure 5-37. MTDC configuration using series current-source inverters

The benefit and main idea behind using this configuration is to eliminate the transformers that would be needed at each set of wind farms to step up the voltage to the desired value. By placing current-source inverters in series, a voltage is built up from the outputs of the connected WTGs and removes the need for any voltage step-up. In an offshore situation, this can be expensive, because it requires more platform space and increases the weight of the platform, and any weight, space, and cost savings gained by eliminating the transformers may be moot. Designing the onshore transformer to appropriately handle the loss of one or more wind power plants could also be somewhat challenging.

5.6 Cables

Submarine cables provide the critical links in any offshore wind system. They are the connections between the generation and the collector station, and between the delivery station and the onshore terminal. The following discussion describes typical cable technologies as they exist today.

5.6.1 Single-Core and Multi-Core Cables

Cables are differentiated as single-core or multi-core, in which the term *cable* refers to the full cable assembly and the term *core* refers to a fully functional single conductor cable with its associated insulation, electrical screen, and water-blocking sheath. Thus, one cable assembly can have multiple cores, i.e., several individually functional cables within one larger cable assembly. A single-core cable has one cable core that comprises the cable, and a three-core (or tri-core) cable refers to three cable cores laid up into one cable assembly. Examples of a single-core cable and a three-core cable are shown in Figure 5-38.

Single-core cable with lead sheath and wire armor

Three-core cable with optic fibers, lead sheath, and wire armor

Figure 5-38. Single-core and three-core XLPE armored cables (Illustrations from ABB)

In AC cable applications, three-phase power is transferred by either three separate single-core cables or one three-core cable. Single-core cables are normally used for installations onshore. Each of the three cables is laid separately in a trefoil or flat formation. A spare phase (fourth cable) can be laid at the same time to improve the overall availability of the system. Single-core cables can be manufactured and installed in longer lengths to reduce the number of joints or splices because of the smaller diameter than that of a three-core cable. Unarmored single-core cables will also have better current-carrying capacity because of their superior thermal efficiency than that of three-core cables.

Three-core cables are more difficult to handle than single-core cables because of the heavier weight and cable diameter, but all three phases are realized with the installation of one cable. In addition, the circuit can be installed with one pass, instead of three, of an offshore installation vessel. This is quicker and, thereby, avoids extra costs related to the vessel's day rate. For these reasons, three-core cables are common for realizing AC cable circuits in an offshore environment. Three-core cables have also been used for onshore medium-voltage applications, depending on utility preference. The screen/sheath of three-core unarmored cables, or unarmored single-core cables in trefoil, carry much lower currents than single-core cables arranged in flat formation, resulting in lower induced current losses. It is also possible to combine fiber-optic cables with three-core cables, saving operation time and costs for laying a separate fiber-optic cable.

In DC applications, cables are generally single core. Double-core HVDC cables have been used, however, to lay a DC circuit with a single cable. For example, this has been used for the HVDC submarine power cable connection between Norway and the Netherlands (NorNed). Polymeric DC cables, such as those typically used for VSC applications, have been single core. When installed offshore, these are "bundled" together on the installation vessel with string or tape and installed as one.

5.6.2 CABLE STRUCTURE

Several layers of different materials comprise each core. The general structure includes (1) the conductor at the center, which carries the electrical current; (2) a semiconductor layer to smooth the electrical stress around the insulation; (3) the insulation that provides the electrical barrier between the conductor and the other components; (4) a metallic screen that provides a path for fault currents; and, (5) a sheath that is used as a radial water barrier. If armor is required, the core (or multiple cores) is wrapped with armor bedding and with the armor material itself. The cable assembly is completed with an outer protective layer—often referred to as an outer serving, jacket, or cover. Figure 5-39 shows the structure of a typical armored, cross-linked polyethylene (XLPE) submarine cable.

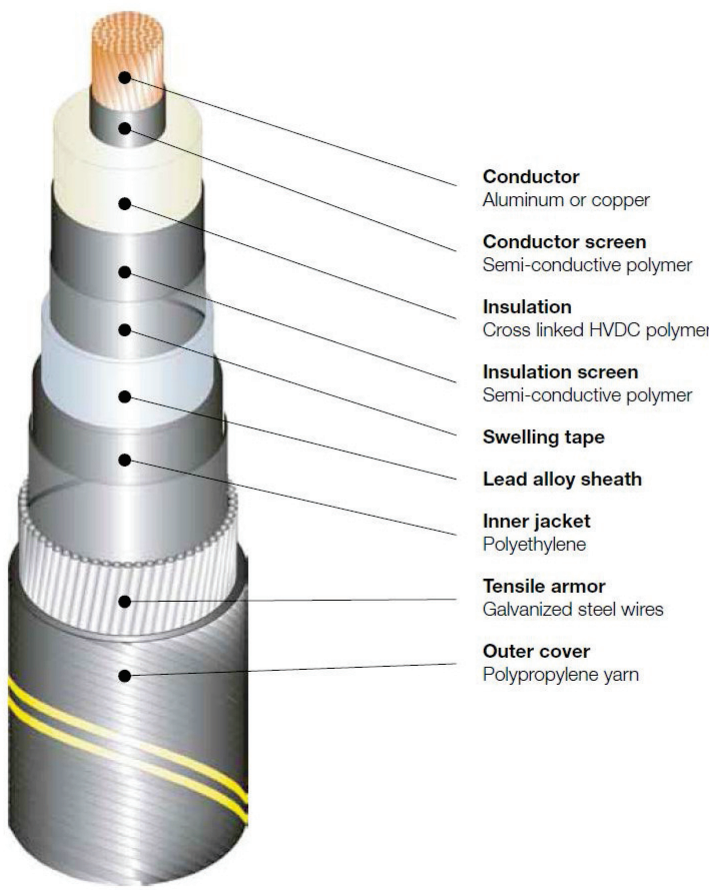


Figure 5-39. Example of single core HVDC submarine cable (Illustrations from ABB Inc.)

Conductors

The conductor is made from either copper or aluminum. Conductors are normally stranded or segmented; the conductor itself is made of many smaller wires bundled together. This is to reduce the skin effect and the associated increase in losses, although there are some projects in which a solid conductor has been used, possibly for its qualities of longitudinal water-tightness and ease of manufacturing [47]. It is possible to connect a copper conductor cable to an aluminum conductor cable with a joint.

Compared to copper, aluminum has been less expensive with less price volatility. Aluminum conductors are also lighter in weight, but they have a lower conductivity and, thus, a lower current-carrying capacity (ampacity) than a copper conductor for the same cross-sectional area. To achieve the same current rating as copper, the cross-sectional area of an aluminum conductor needs to be about 1.6 times larger, but even then it will still weigh 20% to 40% less than the copper conductor equivalent. This equates to lighter onshore cables, which makes installation on land easier.

In three-core submarine armored cables, in addition to the screens/sheaths, the amount of steel wire armor increases substantially with conductor size. For medium-voltage cables, the weight savings of an aluminum conductor is only 10% to 20%; for HV cables, the weights are about equal. The advantage of aluminum for submarine cables is, therefore, not apparent. This is one of the reasons copper conductors are commonly used for submarine applications; they have been applied to many offshore wind farms already in operation in Europe. The authors are aware, however, that aluminum conductors have been used recently for at least one offshore project [48], and possibly others.

Insulation

Around the conductor is the insulation system. For medium- and HV AC cables, three types of insulation systems are commonly used. Each is described below.

- **Low-pressure oil-filled or low-pressure fluid-filled insulation**—This type of insulation system uses synthetic oil to impregnate the insulation paper. The pressure of the oil is usually maintained by pumping stations on each end of the cable. This type of cable can be made only in lengths up to approximately 50 km (30 mi) because of the distance limits for the oil feed. This reduces the applicability of low-pressure fluid-filled cables for DC systems, which are generally preferred for long-distance power transfer. Low-pressure fluid-filled cables have been widely used for submarine AC transmission systems in the past; however, because of their complex structure and the potential environmental hazards of leaking fluid, their application in current offshore market has been reduced.
- **XLPE insulation**—This is the favored option for AC cables. Compared to low-pressure oil-filled AC cables of similar rating, XLPE cables have lower cost and lower losses. XLPE insulation is light, mechanically robust, and can be manufactured quickly. XLPE is a standard insulation type for land cables up to 420 kV and has been used for three-core submarine cables up to 245 kV. In addition, a 420-kV three-core submarine cable project was recently completed in 2013. The maximum normal operating temperature for XLPE in HV and EHV applications is 90°C. For U.S. MV applications, land cables are available with 105ºC maximum operating temperatures [49].
- **Ethylene propylene rubber (EPR)**—EPR insulation is similar to XLPE and the preferred option for some utilities, especially for medium-voltage cables. EPR is known to have an insulation strength that is generally inferior compared to XLPE, especially early in the cable life. However, the insulation performance of EPR does not deteriorate as quickly as XLPE. EPR has higher electrical losses compared to XLPE. The temperature withstand of EPR insulation is very good, with a normal maximum operating temperature of 90°C; whereas newer versions may have a normal maximum operating temperature of 105°C [50]. (This may vary by manufacturer and utility standards.)

The following insulations have primarily been used for DC cables:

- **Mass impregnated paper insulation**—This type of insulation system consists of layers of paper, which are heated, subjected to vacuum, and impregnated with high viscosity oil over several months. Mass impregnated paper cables do not have the leaking risk associated with low-pressure fluid-filled cables [47]. Mass impregnated paper is not used for AC applications because of problems with partial discharge. Because of the lack of rapid polarity reversal, this is not an issue for DC applications. The mass-impregnated paper-insulated cable has a maximum operating temperature of only 55°C; thus, a larger conductor is needed for the equivalent voltage and current compared to polymeric-insulated DC cables [51].
- **Cross-linked DC polymer insulation**—This type of insulation is closely related to XLPE, but it is usually addressed with different terminology because it is a cross-linked polymer specifically modified to withstand DC stresses. The compound formula may differ by manufacturer. The extruded polymer insulation is widely used for VSC HVDC applications up to (at the time of writing) 320 kV DC. It is anticipated that the capability will be improved to 500 kV DC during the next decade. Until then, the cables are limited to the 320 kV DC range.
- **Polypropylene-laminated paper**—This is a derivative of mass-impregnated paper insulation that has a track record for AC applications, but not for DC, although it has been promoted for such applications in recent years [52] [53] [54]. Manufacturers state that polypropylene-laminated paper can withstand DC voltages up to 600 kV and achieve operating temperatures up to 85°C to 90°C [51]. The authors are not aware of any cables in operation that use this type of insulation.

<u>Screen and Water-Blocking Sheath</u>

Outside the insulation is the cable screen. The screen is a metallic layer that is grounded and carries fault currents during an electrical fault. In AC applications, care must be taken when grounding cable shields, because doing so at multiple locations results in induced circulating currents in the screen. This creates additional power losses, reduces the cable current-carrying capacity, and produces additional magnetic fields. There are several materials and designs for cable screens. Among the most common are extruded lead alloy, copper tape, and copper wire.

The sheath is referred to as the layer that prevents moisture ingress. The design of the screen is linked to the design of the sheath. A conventional design for HV cables is a lead alloy sheath, which is completely water impermeable and resistant to corrosion. In this design, the lead sheath also functions as the screen in that it is also used to carry fault currents. For single-core cables, a polymeric jacket is applied over the metallic screen/sheath to protect it from humidity and corrosion.

Note that the polymeric jacket may be referred to as the sheath, depending on the manufacturer and region, and particularly for three-core or armored cables in which it acts as the radial water barrier but is not the outermost exposed layer of the cable. In this case, a copper wire or tape screen is used with a polymeric sheath that lies on top of the screen. Polymeric sheaths may allow water vapors to diffuse through, which is acceptable for medium-voltage cables—for 34.5 kV, and possibly up to 69 kV—and is often referred to as a "wet" design. Wet designs are rarely acceptable to U.S. utilities for land-based installations. However, a review of these designs for use in the offshore environment may be warranted.

For higher voltages, a conductive laminate is commonly placed between the wire screen and the polymeric sheath to make the core completely water tight, i.e., a "dry" design [47]. The standard laminate in the United States is copper, but aluminum is also available and may result in a lower cost cable.

The terms *wet* and *dry* discussed above should not be confused with the terms *semi-wet* or *semi-dry*, which refer to a three-core cable that allows seawater to penetrate the outer serving and armor, thus saturating the filler ropes in the interstices between the cable cores [47]. Note that this terminology is often confused or intermixed, and it often varies by manufacturer.

Armor

Cables may be armored depending on the application, the level of protection required, and the perceived threats that could damage the cable. The armor increases the cable's tensile strength and protects the cable from hazards that could damage the cable and otherwise cause a mechanical failure. The cable core or multiple cores are wrapped first with a binding tape and then a bedding layer, such as polypropylene yarn, to protect the core(s) from the armor. The armor is applied to this bedding.

Three-core submarine cables are typically armored to protect the cable from hazards and to give tensile strength to support the cable's own weight during installation. Armor can also make the cable suitable for different sea-bed conditions. A traditional design for three-core cables is round steel wires, although flat wires may also be used to reduce cable diameter. Steel wires are galvanized for corrosion protection. Although other materials can be selected for the armor, galvanized steel wires have better tensile properties and lower weight than nonmagnetic materials, such as copper. However, magnetic losses may be significant, as estimated according to IEC 60287 [52][53][54]. This is especially the case for single-core AC cables; therefore, nonmagnetic materials (copper, aluminum alloy, or non-magnetic stainless-steel wires) are used to avoid magnetic losses. There are no magnetic losses for DC cables, so galvanized steel wires can be used for the armor.

Multiple layers of armor can be applied to provide additional stability, protection, and torsional strength to the cable, although attention must be given to the direction of the wires in each of the armor layers. A single unidirectional armor layer—or multiple layers wound in the same direction—allows the cable to coil and be stored in a static or fixed tank. This can be advantageous in terms of the type of vessel required and can impact installation costs. An even number of armor layers applied in a counter-helical arrangement gives the cable high balanced torsional strength, although the cable cannot be coiled and a turntable or carousel must be used for storage, transportation, and installation [47].

5.6.3 LAND AND SUBMARINE CABLES

For offshore use, an AC circuit is typically realized with one three-core cable. For onshore use, an AC circuit is typically realized with three single-core cables. A circuit with both an onshore and offshore component has a transition joint bay, located very close to landfall. The individual cores of the submarine cable are split out and jointed to the land cables, and the armor is earthed.

For DC applications, single-core cables are normally used. Offshore, two single-core cables are bundled together with tape or string and installed as one. A transition joint bay is also required at landfall where the submarine and land cables are jointed together and the armor of the submarine cable is earthed.

Submarine cables are often manufactured and delivered in the longest lengths possible to minimize the need for risky and costly field joints. The long lengths are accomplished with factory joints for the cores and a continuous longitudinal lay-up process of the cable assembly, resulting in very long continuous and seamless lengths of cable. To accommodate the long lengths, the cables are loaded, transported, and installed in long spools, using static tanks or turntables (depending on the cable design).

Land cables, meanwhile, are produced in lengths between a few hundred and few thousand meters long, depending on cable diameter and installation requirements. Spools of cable are transported to the site and installed via wooden or steel drums. The lengths of cable are jointed together using joint kits or bespoke techniques, depending on the manufacturer and cable type.

The electrical power losses—thus, ampacity of the cables—are partially dependent on the currents flowing in the metallic screens of the cables. The screen currents are magnetic losses generated from the alternating magnetic field. Derivatives of this are circulating currents, resulting from the screen being earthed on each end of the cable. The cables can be "cross-bonded" at cable joint locations—the screens are sectionalized and connected to each other to earth. This minimizes circulating currents and increases the ampacity of the cable circuit.

5.6.4 Distance Limitations of AC Cables

AC cables are widely used over relatively short distances in onshore networks and are also preferred for connecting offshore wind farms located within reasonable distance of the grid connection point. As touched on previously, the ultimate restriction on the applicable length of AC cables is the high-capacitive charging current for long cables, which can swamp the cable's capability to transfer real power. These negative effects can be partially mitigated by installing reactive compensation (shunt reactors) at one or both circuit ends, and even mid-route for long cable circuits. Figure 5-40 shows the maximum real power transfer capability of 2,000 kcmil, single-core, copper cables (with wide spacing between cables and an ampacity rating of 1,265 A) at different voltage levels and with different locations for the reactive compensation. As shown, longer cables result in lower real power transfer capability. In addition, the transfer capability drops more rapidly with length as the operating voltage increases. Above certain lengths, the higher operating voltage levels, which are often selected with the intent to increase power transfer capability, actually result in lower real power transfer capability than operating at lower voltages and providing similar compensation. Reactive compensation at only one end of the circuits is not as effective as reactive compensation at both ends.

Three-core, steel-wire, armored cables have been used for many, if not most, offshore wind generation projects to date. The real power transfer capabilities for 2,000 kcmil, three-core, copper cables (ampacity 825 A) show similar behavior as illustrated in Figure 5-40. Note that Figure 5-40 and Figure 5-41 are determined for 60-Hz systems. The charging current will be different for 50-Hz systems, allowing slightly greater power transfer.

The transfer distance of HVDC cables is not restricted by charging-current limitations. Compared to equivalent AC cables, HVDC cables generally operate at higher voltages to transfer larger scale power. HVDC cables are preferred for high power transfer through relatively long-distance connections in both onshore and offshore networks.

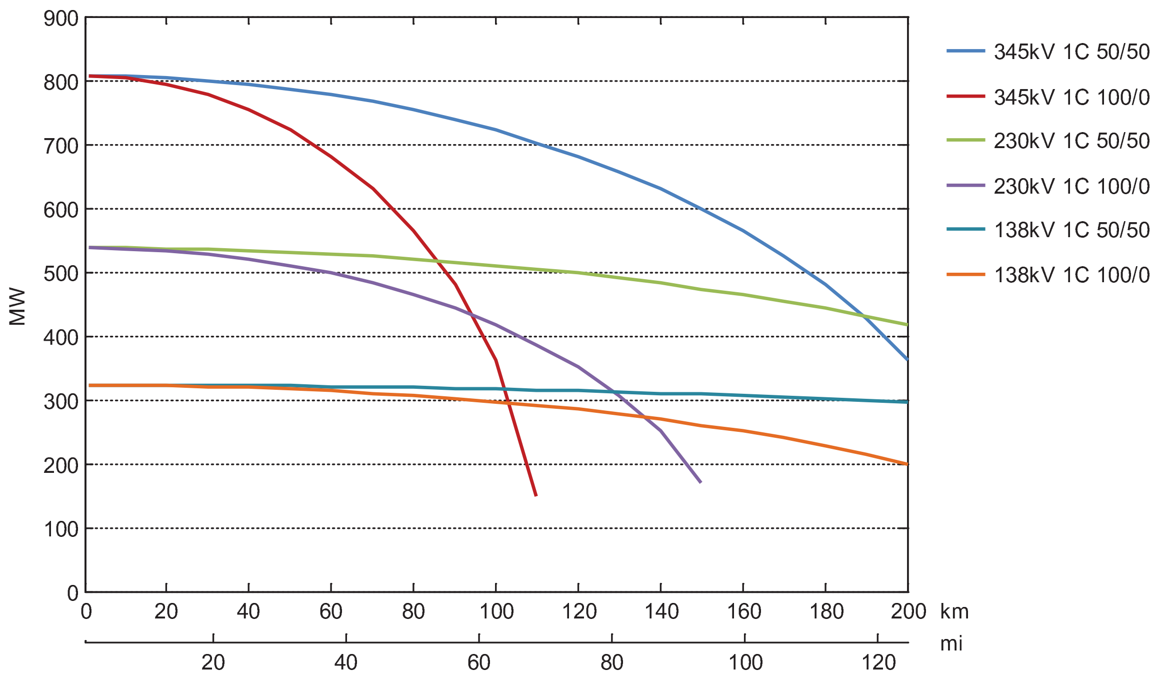


Figure 5-40. Maximum real power transfer in 138-kV, 230-kV, and 345-kV 2,000-kcmil, single-core, copper cables (wide spacing) with onshore/offshore reactive compensation splits of 100/0 and 50/50

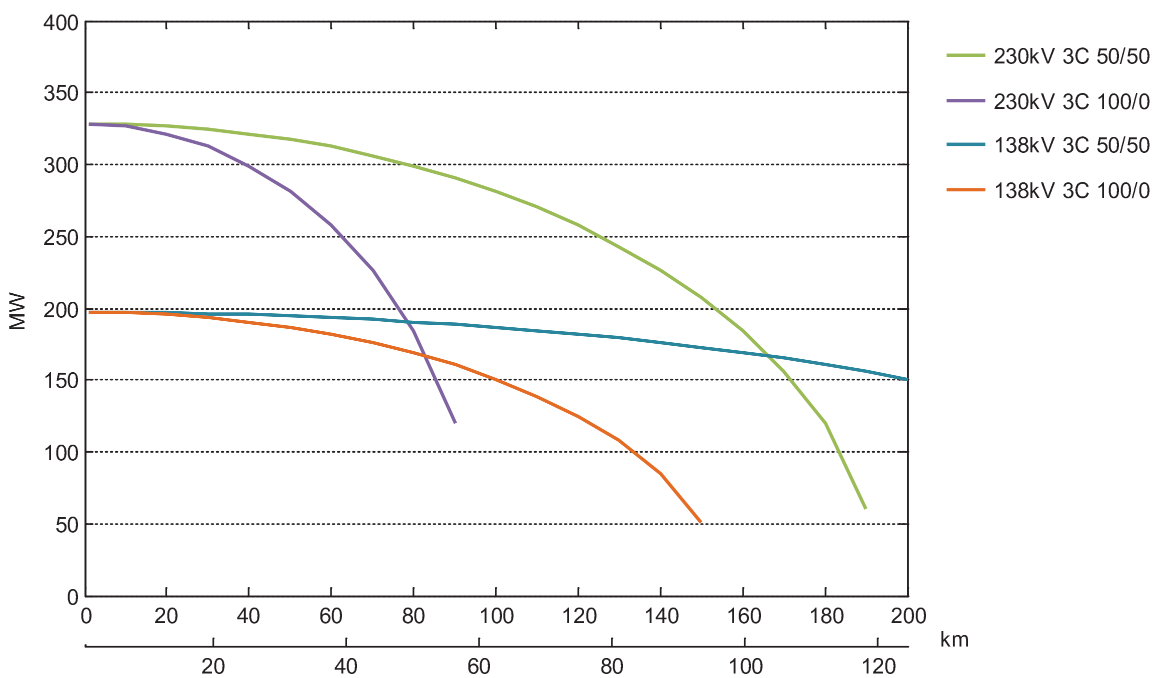


Figure 5-41. Maximum real power transfer in 138-kV, 230-kV, and 345-kV 2,000 kcmil, three-core, copper cables with onshore/offshore reactive compensation splits of 100/0 and 50/50

5.6.5 CONSIDERATIONS FOR COST REDUCTION

Below are the topics that have scope for research and development to lead to cost reduction.

- **Insulation technology is a key area for future development.** If the maximum continuous temperature can be increased, the current-carrying capacity per circuit would be extended, reducing the number of circuits or reducing the conductor size required. As noted, normal maximum continuous current temperature is 90°C for HV and EHV XLPE insulation and 70°C for cross-linked DC polymer insulation.
- **The maximum voltage of cross-linked DC polymer insulation is understood to be 320 kV DC at the time of writing.** Increasing the capability of this insulation for voltages beyond 320 kV would decrease costs for HVDC systems that require voltages greater than ±320 kV DC.
- **The capacitance value in the specification of AC cables should be limited to reduce the capacitive charging current produced by the cables and, thus, extend the range and capacity of AC cable circuits.**
- **The losses in the cable screen/sheath and armor of a three-core AC cable can account for up to half the losses in the whole cable, according to IEC 60287 Part 1-1 [52].** A better cost-effective and non-magnetic armor design may reduce armor losses and, therefore, increase cable ampacity. This could be accomplished through the use of materials with low magnetic permeability, such as stainless-steel wire or alternating plastic and galvanized-steel wires.
- **Several recent papers [55][56] have questioned that armor losses may be overestimated as calculated by IEC 60287 Part 1-1 [52].** Finite element analysis can be used to calculate cable losses and thermal rating (i.e., ampacity); therefore, it may result in better selection of an optimized cable size, improving cost-efficiency. The accuracy of the armor-loss calculations in IEC 60287 Part 1-1 should be reviewed and revised, if necessary.
- **Cables may be sized to accommodate the anticipated worst-case thermal event based on historic wind speed data (such as the longest duration of full power output), rather than according to the rated capacity of the wind farm.** This would improve cost-efficiency by reducing conductor sizes, which may otherwise have been sized to allow for capacity that would be never or only rarely used. This should be incorporated into a standard used to size cables (by calculating ampacity), such as IEC 60287 or IEC 60853.
- **New solutions (or effective mitigation) for hot spots in an offshore wind farm's cabling system can lead to the reduction of cable sizes and cost.** Common hot spots are the entry systems to the wind turbines and marine substation (typically via J-tubes) and at landfall.
- **For any project, it is prudent for a cost-benefit analysis to be undertaken for the design options.** This should include an evaluation of whether redundancy in the cable delivery or collection system is worth the extra cost of its implementation. This should take into account the probability of a cable failure, based on how well the cables can be protected, and the resultant cost of lost production because of an unavailable delivery system.
- **A risk-based approach should be taken regarding the full life cycle of the cable system from concept development through commissioning, operations, and maintenance.** Recommended practice DNV-RP-J301 provides guidance on this [57]. Of particular importance is the design of the cable route and the installation and protection of the cables. The design of the cable—parameters such as diameter, weight, tensile strength, and the ability to coil—also directly impact the costs and risks to load-out, handling, and installation.

- **Costs may be reduced by simplifying the design and using less-expensive raw materials.** For instance, when it is feasible and does not compromise cable performance, wet designs could be used.

5.7 Marine Substations and Platforms

5.7.1 SUBSTATIONS

The electrical substations for the collector and delivery systems are housed on offshore platforms. For AC networks, these are generally on the same platform, so that the cables from the wind turbine strings terminate through switchgear into a medium-voltage bus. The voltage is then stepped up to a higher voltage through a transformer, and the delivery system cables to shore are connected through appropriate switchgear at the higher voltage rating. To minimize space requirements for the substations, gas-insulated substations can be used.

For HVDC systems, multiple platforms may be used, although they are not necessarily required. If they are used, the AC collector system along with the step-up to a higher AC voltage will be accomplished on one platform, with the conversion to HVDC on a separate platform. This would be done primarily to keep platform sizes within the capability limits associated with existing lift barges. However, with new platform technologies, as discussed below, these limitations are removed and the collector and converter systems can be housed on the same platform.

The primarily difficulty with the HVDC systems from a platform perspective is the large volume of space required for the converters. They are completely enclosed in rooms with controlled environments and are, at present, air insulated. This means that, although higher voltages help transport greater power levels, larger clearances to walls and other equipment is required, which likewise increases the size and weight of the platform. Similarly, the current layout of converters, and the need to access equipment for maintenance or possibly for removal and replacement, tends to add to the space requirements of the converter rooms. Efforts are underway at the manufacturers to identify ways to make compact HVDC stations. If these efforts prove successful, they will go a long way toward reducing the size requirements of the HVDC platforms, and potentially toward lowering the final costs associated with these systems, increasing their economic attractiveness.

5.7.2 PLATFORMS

Platforms provide the housing for all of the substation equipment, personnel quarters (particularly required during installation and maintenance operations), safety equipment, emergency lifeboats, etc. The offshore wind power market requires that the offshore platform design be reliable, cost-efficient, environmental friendly, and perhaps even expandable for higher power ratings. The installation approach should minimize risk and be as independent to weather and transportation restrictions as possible. Three basic types are currently available or in the design and construction phase:

- Conventional jacket and topside
- Jack-up platforms
- Gravity-based platforms

Each type of offshore platform design should consider the key issues for platform fabrication, transport, and installation. For offshore platform fabrication, yard availability is one of the key issues, because wind platforms compete with oil and gas platforms. Coordinating with offshore installation works, minimizing offshore commissioning and maintenance, the health and safety of offshore workers, and compact solutions are also important for platform fabrication. Larger platform fabrication is currently available in only a few countries and requires transportation of the structures on open seas.

Regarding the transport and installation of the platforms, only a few crane vessels in the world have the lifting capacity greater than 1,000 tons, and experience has shown them to be heavily booked. Further, most of the large crane vessels are not suitable for shallow water. The maximum capacity of the largest crane vessel is 14,000 tons, and then only if the cranes can be maintained at the proper lifting angles. Larger platforms are likely to require lower angles, and the lifting capacity will be reduced accordingly. Installing the platform in sections is one option to reduce required crane capacity, but it will increase offshore work, which is much more expensive than completing the platform in dock.

The increased cost of offshore work is also a concern with the tightly booked vessels. If the platform is not ready when the vessel is scheduled, six months to a year or more may be lost until another opening is available. It may become necessary to ship the platforms early and complete them on-site, but this will add significantly to the final project costs.

<u>Conventional Fixed-Platform (Jacket and Topside)</u>

The conventional fixed offshore platform (Figure 5-42) is built on a steel support structure—the jacket—that is anchored directly onto the sea bed and which supports the topside to house the offshore stations. The conventional fixed platform is a well-proven concept that has been reliably utilized in both the petroleum and offshore wind industries. The jacket can be installed in advance and HV cables preinstalled. After installation, the platform has low sensitivity to weather.

Figure 5-42. Conventional jacket and topside platform

A number of shipyards around the world have experience fabricating this type of platform; however, installing and lifting this type of platform is possible only in better sea conditions, which may restrict the installation to certain months of the year. Transporting and installing a large (e.g., 1,000-MW) HVDC station with fixed-platform design may require the world's largest crane vessel, which has implications of both costs and availability. The installation of large platforms requires multiple offshore lifts of the topside and extensive offshore work [58].

Table 5-1 shows approximate weights of the topside of the platforms for both AC and HVDC applications with different power rating levels [58].

Table 5-1 Typical Weight of platforms (topside)

Substation Type	Power Rating (MW)	Weight (tons)
AC	100	<1000
AC	200	1500
AC	300	2000
HVDC	400	3000
HVDC	1000	10000

<u>Jack-Up Platform</u>

Another type of platform is the jack-up platform (Figure 5-43). This is a floating, self-installing platform that uses a buoyant hull and is fitted with moveable legs that are jacked above the platform during transportation. The platform can be pulled to site with tugs or floated to site on an appropriate barge. Once at site, the legs are carefully jacked down until they rest on the sea floor or

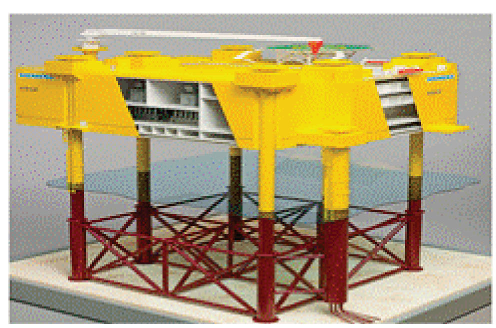


Figure 5-43. Example jack-up platform

perhaps on a preinstalled undersea jacket. As the jacking process continues, the platform is raised to the desire height above sea.

Many shipyards around the world have the capability to fabricate this type of platform; however, current experience is limited to large platforms above 10,000 t. To handle offshore jack-up operation for this weight, a complex design of jack-up system and platform is required, and care must be exercised to jack it in a balanced way.

Two of the large European manufacturers of offshore wind systems appear to prefer this type of platform for larger installations.

Gravity-Based Self-Installing platform

A gravity-based, self-installing platform (Figure 5-44) is a newly developed concept. The platform is constructed onshore and fully commissioned with all the platform systems in dock. The entire structure is then towed to the desired location by tugs and secured on the sea bed by its own weight and ballasting as illustrated in Figure 5-45. This design minimizes offshore connection work and reduces the offshore commissioning work necessary to energize and perform trial runs after installation of the HV cables. This approach does not require a large crane vessel for transportation and significantly reduces the weather dependence of the installation operation.

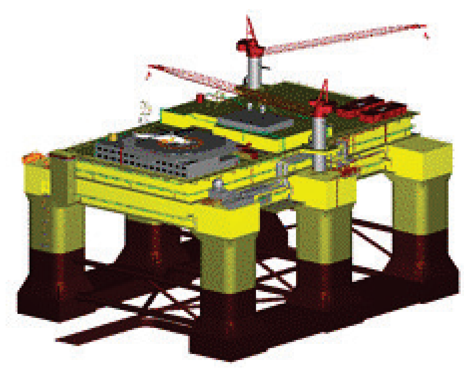


Figure 5-44. Example GBS platform

The gravity-based self-installing platform also facilitates laying cables to the platform. External terminals allow straightforward underwater connections and will greatly reduce the risk of damage to the cables. The gravity-based self-installing platform is also designed to reduce environmental impacts. Although minimal marine operations are required for installation, with only limited sea-bed preparation, eliminating noisy piling operations ensures there is no impact on wildlife. The platform is also easy to remove and decommission at the end of its service life. The gravity-based self-installing platform is mainly intended for use with wind farms in size of 700 MW to 1,100 MW in sea depths of 15 m to 45 m.

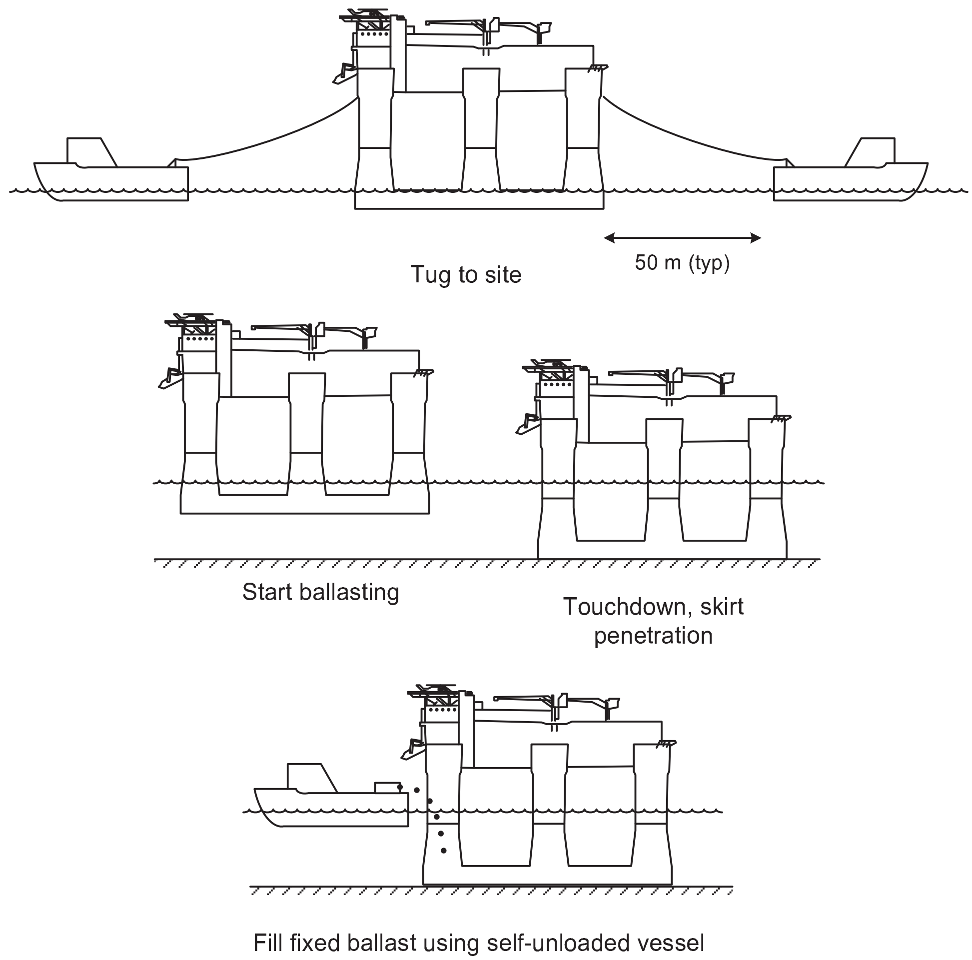


Figure 5-45. Installation of gravity-based structure

Potential Future Developments

Modifications to these platform types or new platform types may be developed as the move to offshore wind to deeper waters becomes possible with new floating turbines that are being developed and have been proven in initial tests. These deepwater designs may require that the substation platforms also become floating, and it would appear that the floating nature of the jack-up and gravity-based structures provide a good place to start.

If such floating designs become well proven, offshore wind farms in deep water quickly become much more viable than was considered in the build-out assumptions in Section 2.0.

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6.0 TECHNOLOGY ASSESSMENTS

The previous sections presented potential technologies and topologies for offshore wind collection and delivery systems. This section reviews them from several practical perspectives: capital cost, reliability, impacts to the onshore grid, and impacts to production costs (i.e., value of offshore wind). Because each of these study areas is dependent on site, technology, and manufacturer, these reviews were performed as general assessments that indicate the main trends, costs, and benefits that can be expected from the technologies. Any individual project should determine the specific details as applicable.

The costs are first discussed, along with a brief review of some cost-reduction efforts occurring in the United Kingdom and United States. The reliability of several of the system topologies discussed in the previous sections is then presented. The next two sections discuss the steady-state performance and impact of offshore delivery topologies—first in a generic system, then in the specific systems in the Carolinas, ERCOT, MISO, NE-ISO, and PJM regions. Finally, analysis is presented that estimates the value of offshore wind from the perspective of production cost savings.

6.1 Costs and Trends

In the process of compiling the information for this report, the authors encountered limited willingness from manufacturers to share potentially proprietary information regarding costs of components that are used in offshore collection and delivery systems. Therefore, publically available information has been utilized for estimating the costs and cost trends of offshore equipment.

Because the offshore wind market is still new in the United States, cost savings are expected as the technology, planning, manufacturing methods, and offshore platforms continue to improve. This may be particularly true for offshore platforms, because they are not currently used by the power industry. Industry efforts to achieve these cost savings are ongoing, and a brief review of efforts in the United Kingdom and United States is presented before the equipment capital costs are provided.

6.1.1 COST-REDUCTION EFFORTS IN THE UNITED KINGDOM

Cost-reduction efforts in the United Kingdom are presented here from the perspective of the task force that is currently in place as documented in a 2012 report [1] and with a stated goal given of reaching £100/MWh (approximately $154/MWh). The United Kingdom has already deployed a large amount of offshore wind, so it is seeking to lower the cost of the power provided.

The U.K. report is divided into five sections, each focusing on an area that could lead to the cost reduction of offshore wind deployment: supply chain, innovation, contracting strategies, planning and consenting, grid and transmission, and finance.[5] Reviewing and learning from the U.K.'s efforts toward offshore wind cost reductions will help the United States in its own endeavors in offshore wind deployment.

Regarding the supply chain of equipment necessary for offshore wind, it is important to identify bottlenecks to prevent any setbacks to project timelines after the projects have been set into motion. In general, supply chain limitations are not specific to turbines or offshore wind; they span across the entire electric power industry. Typical bottlenecks tend to be found in the production of transmission and distribution equipment, such as transformers, cables, or HVDC components. There is also a need for new onshore transmission equipment to create capacity for offshore wind connections. As a follow-up to

[5] This is fairly similar to the categories outlined for the DE-FOA-0000414, of which NOWEGIS is a portion.

bottleneck identification, government engagement was recommended to encourage companies with offshore wind manufacturing capabilities to work toward improving supply chain efficiencies.

Innovations in certain technological fields were also identified that could lead to cost reductions in offshore wind systems. Many of these reflect ideas and concepts identified during the NOWEGIS development. In particular, these included technology developments in the fields of turbines, foundations, substation design, and cables, among others. Larger turbines with higher power output and increased reliability would be of great benefit, because it is difficult to replace or upgrade previously installed turbines. These larger turbines also greatly assist in reducing the total levelized cost of energy (LCOE).

Another key innovation area is with regard to testing sites. Sites allowing for the testing of newer technologies are necessary to guarantee a noticeable difference in reliability, maintainability, and structural efficiency compared to current technologies. This would increase confidence in the deployment of the newer technologies.

The last key point for innovations was to develop standards for the necessary areas within the offshore wind market. Having standards for the fields mentioned brings huge advantages. Common standards will help eliminate incompatibilities and problems in the future for integrating offshore wind grid systems, and they will allow different forms of equipment to communicate more easily. This would then provide developers with more options for purchasing or replacing equipment, because commonalities will be in place among all of the options available.

Contracting strategies are the third area considered in the U.K. task force report. A major suggestion is to seek an “alliancing” approach, building on the observed success of other industries that have used these methods. Alliancing would directly impact the efficiency of the supply chain and thus lead to a reduction in COE and LCOE. A standardized approach to technology, processes, and contracts is also suggested. A streamlined approach would be available to those that adopt these standards, which would be based on best practices for contracting. Thus, continuous monitoring of the offshore wind market is necessary to identify new barriers and address them actively so that the approaches continue to be effective.

Preventing proposed projects from stalling in the planning stages or being postponed as a result of delayed permitting can be accomplished by implementing a maximum time limit to which a project would be subjected during the permitting process before receiving feedback. If possible, working together with environmental agencies during the evaluation process to establish clear conditions for offshore wind sites would prevent even further delays. Similarly, in the United States the offshore wind industry will need to work with the various federal, state, and local governments to reach collaborative solutions to issues as they arise. The roles of different government agencies within the United States regarding the permitting of offshore wind are discussed in a Congressional Research Service report. [2]

The U.K. report also indicated that costs can be lowered by adjusting certain aspects of the grid and transmission sector. As mentioned previously, standardization within the grid and transmission would lead to cost reductions in design, manufacturing, installation, and operations and maintenance. It is important, however, to first determine the aspects for which standards would be appropriate. One aspect to consider for transmission is increasing the voltage rating of HVDC extruded XLPE undersea cables. This is practically inevitable because of the nature of evolving technology, and this would allow for more power (in the gigawatt range) to be transferred through the cables, resulting in fewer required high-capacity links [1]. Research on this topic has been conducted at the 500-kV level [3]. A more in-depth research paper pertaining to 500-kV XLPE cables can be found in a five-part series that begins with [4].

6.1.2 Cost Reduction in the United States—Advanced Technology Demonstration Projects

In 2012, DOE announced $168 million throughout six years for seven advanced technology demonstration projects listed in Table 6-1. [5] These projects seek to utilize innovative technology or installation designs that could reduce the cost of offshore wind deployment.

Table 6-1. DOE Offshore Wind—Advanced Technology Demonstration Projects

Demonstration Name	Capacity (MW)	Advanced Technology to be Demonstrated
Baryonyx Corporation	18 MW	Install three 6-MW direct-drive wind turbines in state waters near Port Isabel, Texas. The project will demonstrate an advanced jacket foundation design and integrate lessons learned from the oil and gas sector on hurricane-resistant facility design, installation procedures, and personnel safety.
Fishermen's Energy Atlantic City Wind Farm	~25 MW	Install up to six direct-drive turbines in state waters 2.8 mi from Atlantic City, New Jersey. The project offers innovative bottom-mounted foundation design and environmentally-friendly installation procedures. Project will demonstrate the sourcing of local materials to reduce costs of installation.
Lake Erie Development Corporation	27 MW	Install nine 3-MW direct-drive wind turbines on "ice breaker" monopole foundations designed to reduce ice loading. The 27-MW project is based on Lake Erie, 7 mi off the coast of Cleveland, and it is designed to reduce ice loading.
Principle Power/Deepwater Wind—WindFloat Pacific	30 MW	Install five semisubmersible floating foundations outfitted with 6-MW direct-drive offshore wind turbines. The project will be 10 mi to 15 mi from Coos Bay, Oregon, and seeks to demonstrate floating-foundation technology for deepwater applications that are more than 30 m. The project also seeks to reduce installation cost through local assembly.
Statoil North America	12 MW	Planned to deploy four 3-MW wind turbines on floating spar buoy structures in the Gulf of Maine off Boothbay Harbor at a water depth of 460 ft (137 m). By utilizing local assembly and towing the turbines to the deep waters off the coast of Maine, the project would demonstrate floating-technology and installation methodologies that could reduce costs. Project cancelled.
University of Maine	12 MW	Deploy a pilot floating offshore wind farm with two 6-MW direct-drive turbines on semisubmersible foundations near Monhegan Island. This could help establish a cost-effective alternative to traditional steel foundations through design and local assembly. The project would also demonstrate floating technology for applications in deep water more than 100 ft (30 m).
Dominion Virginia Power—Virginia Offshore Wind Technology Assessment Program (VOWTAP)	12 MW	Plans to design, develop, and install two 6-MW direct-drive turbines off the coast of Virginia Beach on innovative "twisted jacket" foundations. The project offers the potential for significant cost reductions compared to traditional jacket foundations by using substantially less steel.

In mid-2014, three of these projects were selected to move forward the second stage of deployment: Fishermen's Energy Atlantic City Wind Farm; Principle Power/Deepwater Wind's WindFloat Pacific project; and Dominion Virginia Power's Offshore Wind Technology Assessment Program.

6.1.3 Capital Cost Estimates

This section presents estimates of the breakdown of offshore capital costs. This information is useful, not only when roughly estimating project costs, but also to identify the components that would provide the largest benefits from cost-reduction efforts. Also, to prioritize efforts it is useful to categorize these components as either long-term or short-term cost-reduction opportunities. Certain cost reductions may appear only after more research and development is carried out (i.e., increased voltage ratings of XLPE undersea cables) and would fall in the long-term category. Further, continuous monitoring of offshore wind capital costs will help to direct the course of research and development efforts and other appropriate actions in the future.

The most recent version of NREL's *2011 Cost of Wind Energy Review* report [6] states that there are no major differences in cost between 2010 projects and 2011 projects. With relatively low inflation in the interim, it seems reasonable to assume that costs have not dramatically diverged from where they were when estimated for that report. Based on a literature review, interviews with active offshore wind developers, and global market analysis, the report found that the average cost for an offshore wind installation is $5,600/kW. The complete range was between $4,500/kW and $6,500/kW. These values do not account for issues such as transmission, environmental impacts, military constraints, public policy, consumer costs, energy prices, or public acceptance. An approximate breakdown of the costs for installed offshore wind is shown in Figure 6-1.

When studying reductions for the total cost of offshore wind installations, the most obvious targets are categories that comprise the largest percentage of the total cost—that is, turbine installation (including assembly and transport) and support structure. It is especially important to consider costs of the turbines. If similar costs can be maintained with new turbine technology and without drastically affecting the other categories, a gain in efficiency or output power will still be realized. Note that the second- and third-highest percentage categories are both contained within the "Balance of Station" section shown in Figure 6-1. From a cost standpoint, it may be possible that future platforms could affect the support structures as well as their assembly, transport, and installation. This could result in significant cost savings as well.

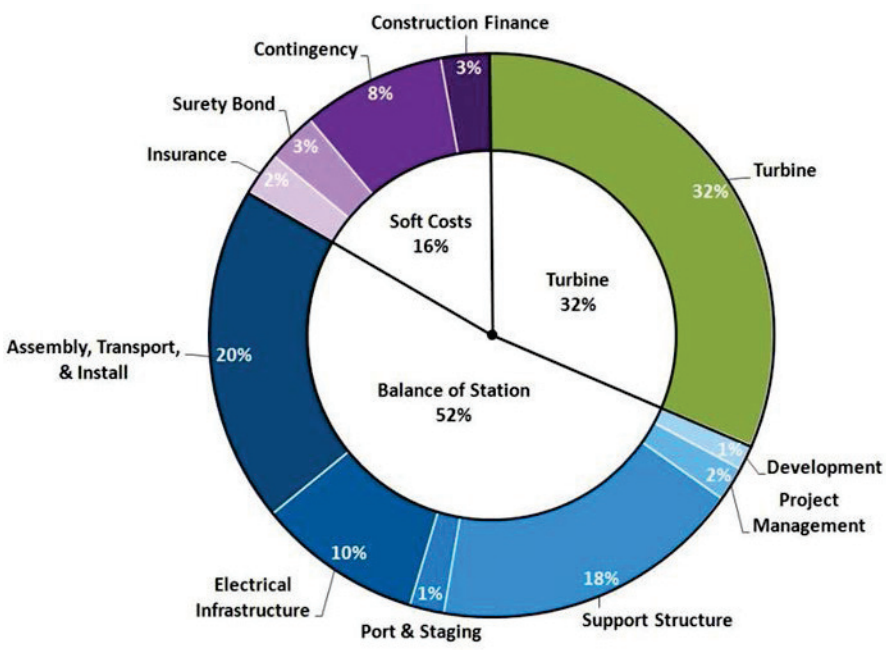


Figure 6-1. Installed capital costs for 2010 reference offshore wind

Although the larger contributors to the overall cost of the installation may have the most impact on cost reductions, the smaller percentages shown in Figure 6-1 should not be disregarded. Some of the suggestions in Section 6.1.1 may not easily fall into one of the categories shown in Figure 6-1. These are still important to consider when seeking cost reductions and might have been beyond the scope of the analysis in [6]. It may also be possible that several smaller cost reductions could aggregate into larger cost reductions.

6.1.4 Cost Estimates for Various Offshore System Components

Four main component categories are presented in this section: HVDC converters, AC and DC cables, HVAC components, and offshore substation platforms. The costs of installation for the cables and platforms are also presented.

The cost estimates have been derived from two public domain sources in Europe: National Grid's Offshore Development Information Statement (ODIS) in Great in Britain [7] and an offshore transmission report by the European Network of Transmission System Operators for Electricity (ENTSO-E) [8]. The costs in these reports are based on prices from existing projects and from dialogue with suppliers.

To determine costs in terms of U.S. dollars ($USD) for this report, the costs from the ODIS and ENTSO-E reports were converted from pound sterling (GBP or £) and Euro (€) to U.S. dollars, respectively, using the exchange rates [9] and inflation factors [10] shown in Table 6-2. The two sets of data were compared to each other in terms of 2014 $USD. When the data sets did not align, the authors used their best judgment to select the most appropriate data source. The authors also checked and adjusted the costs as appropriate, based on their experience and knowledge of the power systems market in the United States.

Table 6-2. Conversion Factors for Costs of Offshore Wind Equipment

Report	Year	Exchange Rate	Inflation Factor
ENTSO-E	2011	€0.75 per $1	1.05
ODIS	2009	£0.667 per $1	1.09

The authors note that the costs in this report are indicative and are intended to be used as a guideline only. Costs for transmission equipment and installation may vary significantly by geographical location and also by project requirements. Note that in some cases considerable variations in price can be found among different suppliers for the same types of equipment.

HVDC Converters

The cost estimates shown in Table 6-3 do not take into account the necessary platform installation, but they do include the cost of an AC switchyard. The larger converter ratings are projections that are representative of next-generation technologies. Ratings and costs of various VSC technologies are included.

Table 6-3. Approximate Cost of Various HVDC VSCs

Converter Rating	Cost ($M)
500 MW, 300 kV	105–130
850 MW, 320 kV	140–150
1,250 MW, 500 kV	170–210
2,000 MW, 500 kV	200–275

Cables

Approximate costs for subsea HVDC and HVAC cables are provided in Table 6-4 and Table 6-5 respectively. The approximate costs for HVDC overhead lines and underground cables are listed in Table 6-6.

The most expensive component of a cable is the conductor material, which is typically copper for subsea applications. Additional costs result from a copper screen, if used, followed by the lead sheath. The material costs of the cable can range from 20% to 50% of the total cost. The difference in cost across voltage levels results from the need for thicker insulation at higher voltages.

Because each connection to offshore facilities will include some portion of onshore transmission, terrain issues—such as roads, railroad tracks, or other difficult topography—become a factor in the total cost when installing cables. These terrain-specific costs are not taken into account for the underground cable cost estimates. The total cost is also affected by the number of circuits being buried and how many trenches are required.

Table 6-4. Approximate Cost for HVDC Extruded Subsea Cables

Conductor Area (mm^2)	HVDC Extruded Subsea	
	± 150-kV Cable Bipole	± 300-kV Cable Bipole
	Installed Cost ($/m)	Installed Cost ($/m)
1,200	325–645	485–730
1,500	405–645	485–730
1,800	485–730	485–810
2,000	485–810	565–925

Table 6-5. Approximate Cost for Various HVAC Three-Core AC Subsea Cables

HVAC Three-Core Subsea Cables		
Rated Voltage kV	MVA Rating	Installed Cost ($/m)
132	200	730–1,130
220	300	810–1,210
275	400	1,050–1,615

Table 6-6. Approximate Cost for HVDC Overhead and Underground Lines

Conductor Area (mm2)	HVDC Underground Cables	
	±300-kV Cable Bipole	
	Capacity (MW)	Installed Cost ($/m)
500	404	1,195
1,000	620	1,430
1,400	770	1,620
2,000	866	1,900
2,400	1,089	2,085
3,000	1,253	2,370

HVDC Overhead Line	
Bipole Voltage	Cost ($/m)
+/- 150 kV	1,230
+/- 300 kV	1,390
+/- 600 kV	1,800

HVAC Components

The cost for most HVAC components discussed below can be expressed on a per-MVA or per-MVAr basis. Another driver is the voltage rating. The exception is HVAC gas-insulated substation switchgear, for which the cost is based on voltage and current ratings to determine total price.

Table 6-7 through Table 6-12 list the approximate costs for: transformers; HVAC gas-insulated switchgear; HVAC shunt reactors; HVAC capacitor banks; HVAC static VAR compensators (SVC); and static compensators (STATCOM)

Table 6-7. Approximate Cost of Transformers

Rated Voltage kV	MVA Rating	Cost ($M)
132 / 11 / 11	90	1.10–2.10
132 / 33 / 33 132 / 11 / 11	180	1.60–2.95
132 / 33 / 33	240	2.00–3.25
275 / 33	120	2.00–2.60
275 / 132	240	2.45–3.25
400 / 132	240	2.90–3.55

Table 6-8. Approximate Cost for HVAC Gas-Insulated Substation Switchgear

Rated Voltage kV	400	275	132
Cost ($M)	6.15–6.65	4.70–5.20	1.80–2.25

Table 6-9. Approximate Cost for HVAC Shunt Reactors

Voltage (kV)	Reactive Power (MVAr)	Cost ($M)
13	60	0.80–1.30
275	100	3.85–4.20
400	200	3.55–3.90

Table 6-10. Approximate Cost for HVAC Capacitor Banks

Reactive Power (MVAr)	Cost ($M)
100	3.45–8.10
200	6.45–11.30

Table 6-11. Approximate Cost for HVAC Static VAR Compensators

Reactive Power (MVAr)	Cost ($M)
100	14.45–18.875
200	23.30–27.70

Table 6-12. Approximate Cost for HVAC Static Compensators

Reactive Power (MVAr)	Cost ($M)
100	12.10–19.85
200	27.45–31.20

Platforms and Installation

Offshore platforms and their associated installations are dependent on many factors. The main drivers are size and weight, because they determine which vessels can be used for transportation and installation. Approximate costs for platforms, construction costs of obstacle crossings, horizontal directional drilling and onshore installation are provided in Table 6-13 through Table 6-16.

Table 6-13. Approximate Cost for Various Offshore Platforms

		Cost ($M)		
Total Weight and Rating	**Platform Type**	**Depth 30 m–40 m**	**Depth 30 m–50 m**	**Depth 40 m–60m**
2,000-t platform 132/33-kV 300-MW HVAC	Topside	29.50–36.50	-	29.50–36.50
	Jacket	9.70–16.15	-	12.90–19.40
	Installation	9.70–12.90	-	9.70–16.15
2,500-t platform 220/33-kV 500-MW HVAC	Topside	38.60–44.90	-	38.60–44.90
	Jacket	12.90–16.15	-	16.15–21.05
	Installation	8.10–64.60	-	9.70–16.15
3,500-t platform ± 300-kV 400-MW VSC HVDC	Topside	-	44.90–53.35	-
	Jacket	-	12.90–17.75	-
	Installation	-	25.85–32.30	-
8,000-t platform ± 500-kV 1,000-MW VSC HVDC	Topside	-	96.85–129.15	-
	Jacket	-	32.50–50.55	-
	Installation	-	32.50 – 50.55	-

Table 6-14. Approximate Construction Cost for Subsea Obstacle Crossing of AC and DC Cables

Method	Cost
Concrete mattress/blanket	$4,900
Tubular product	$6,600
Concrete protective structure	$16,400
Diving services/ROV	$3,300
Vessel hire	$49,000–$82,000/d

Table 6-15. Approximate Construction Cost for Horizontal Directional Drilling and Onshore Cable Installations

Trench (m)*	Ground Conditions	HVDC 2 Cables	HVAC 2 x 220-kV Trefoil
Excavate, lay, and backfill (civils only)	Roads	800 $/m	700 $/m
Excavate, lay, and backfill (civils only)	Agricultural land	400 $/m	400 $/m
Jointing pit (every 500 m–1,000 m)	Roads	57,000 $ea	57,000 $ea
Jointing pit (every 500 m–1,000 m)	Agricultural land	16,000 $ea	16,000 $ea
Horizontal Directional Drilling	**Ground conditions**	**HVDC 2 Cables (2 Ducts)**	**HVAC 2 x 220-kV Trefoil (6 Ducts)**
70-m HDD (road crossing)	Normal	$33,000	$98,000
150-m HDD (road crossing)	Normal	$57,000	$172,000
500-m HDD (multiple crossings)	Normal	$328,0000	$984,000
Item	**Description**		**Cost**
Rail crossing	Track monitoring, project management		$410,000–$820,000 per crossing
Reinstatement	Field drains, soil reconditioning. Access may be possible only from April to October		$7,000 per 100 m
Crop damage	Compensation payments		Subject to crop
River crossing	Specific conditions apply (e.g., no access closer than 8 m, environmental surveys)		Subject to specific circumstances

* Obstacle crossing cost (e.g., HDD are in addition to this per m cost)

Table 6-16. Approximate Construction Costs for Shoreline Transitions/Landfall

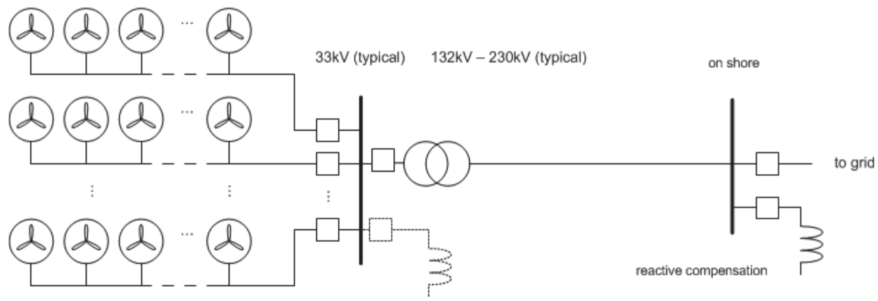
Activity	Cost
HDD 500-m land-to-sea	$1,200,000–$2,100,000
MPV	$66,000–$82,000/d
Diving team	$3,000/d
Transition join pit	$41,000
60-t winch hire	$800–$1,200/d

6.2 Reliability Assessments

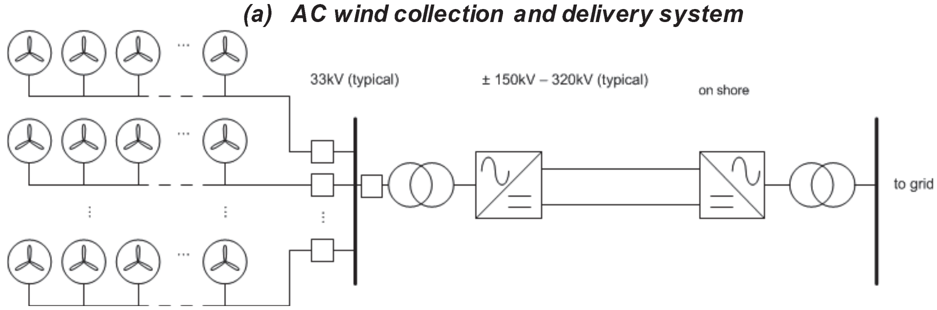
This section analyzes the reliability characteristics of several offshore wind electrical system types and topologies. The electrical power system is held to strict reliability standards, and it is important to lower the rate of failure and minimize outage conditions. This is achieved through proper design choices at both the levels of the components and system architecture.

WTGs with attendant power conversion and transformation devices, a medium-voltage collection grid, an offshore substation on a platform, an HV transmission system, and an onshore substation to connect the farm to the power grid comprise the electrical system of a typical large offshore wind farm. As discussed in Section 5, there is considerable interest in offshore grid infrastructures that would allow the aggregation of power from multiple wind farms and the delivery of wind power to different onshore points. Grid infrastructures would result in lower variability and higher economic value for wind power across a broad regional area.

To obtain a basic understanding of reliability characteristics of offshore electrical systems, the study was performed on two parts: (1) delivery systems and (2) collection systems. Figure 6-2 shows conventional offshore wind collection and delivery systems. The boundary between the collection system and the delivery system is the main bulk power transformer(s) on the collector platform.



(a) AC wind collection and delivery system



(b) AC wind collection with HVDC delivery system

Figure 6-2. Conventional offshore wind collection and delivery systems

The high-level reliability and risk assessment discussed below provides a reference for comparing potential design choices. The assessment of the main system components was performed based on outage statistics available from public sources.

6.2.1 RELIABILITY OF DELIVERY SYSTEMS

This section discusses the reliability of offshore delivery systems and the outage statistics of the main components of HVAC and HVDC delivery systems. The reliability performance of point-to-point connections is evaluated in detail for an example large offshore wind farm. Then the reliability aspects of multi-terminal offshore wind connections are discussed.

Outage Statistics for Reliability Calculations

Table 6-17 summarizes the forced-outage statistics used in the reliability calculations for the main components of HVAC and HVDC delivery systems as discussed in [11], [12], and [13].

The outage statistics show that the failure rates and durations of HVAC components are the same in onshore and offshore installations; however, the repair times are significantly longer offshore because of platform access limitations. The failure rates and durations of cables are the same for HVAC and HVDC, but offshore rates are slightly lower and durations are significantly longer.

Table 6-17. Outage Statistics for HVAC and HVDC Delivery Systems

HVAC Component	Onshore S/S Failure Rate (1/yr)	Onshore S/S Repair Time (h)	Offshore S/S Failure Rate (1/yr)	Offshore S/S Repair Time (h)	HVAC Component	Onshore S/S Failure Rate (1/yr)	Onshore S/S Repair Time (h)	Offshore S/S Failure Rate (1/yr)	Offshore S/S Repair Time (h)
Transformer	0.024	2160	0.024	2160	Converter	1.4	4.3	1.4	24
Circuit breaker	0.02	200	0.02	200	Conv. CMF-C&P	0.063	6	0.063	24
100-km cable	0.133	600	0.1114	1440	Conv. CMF-DCE	0.015	12	0.015	24
Circuit breaker	0.075	3	0.075	24	100-km cable	0.133	600	0.1114	1,440

Note:
Conv. CMF-C&P—Converter common mode failure due to control or protection
Conv. CMF-DCE—Converter common mode failure due to DC equipment

6.2.2 BASIC HVAC AND HVDC CONNECTIONS

To help illustrate the basics of reliability characteristics, the reliability performance of an example 960-MW, point-to-point offshore wind farm was determined assuming an HVAC connection and an HVDC connection. The evaluations were made in terms of the availability of delivery capacity to the power grid onshore and the expected energy not supplied (EENS). It was assumed that the distance from the platform to the onshore substation is 100 km; therefore, the following two connection schemes are technically feasible:

- HVAC connection—This includes double-circuit 230-kV cables with 50/50 split reactive power compensation at the platform and onshore substation.
- HVDC connection—This includes a bipolar ±320-kV link with or without a metallic return cable.

Double-Circuit HVAC Connection

A double-circuit HVAC connection is shown in Figure 6-3, in which the HVAC connection voltage is typically selected to match the interconnection substation onshore. It was assumed that each transformer and each cable circuit have a rating equal to 50% of the maximum wind farm capacity. To maintain the rated delivery capacity, shunt reactors and dynamic reactive compensators might be required at the platform and the onshore substation.

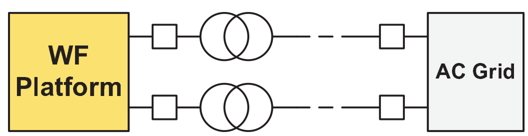


Figure 6-3. Double-circuit HVAC connection

The probability of delivery capacity of the HVAC connection is calculated as follows:

- The delivery capacity is zero when both circuits are unavailable as a result of an overlapping outage, and the probability of zero delivery capacity is obtained by
  $$P_0 = (Q_{transf} + 2Q_{breaker} + Q_{cable})^2$$
- The delivery capacity is 50% when one of the two circuits is unavailable as a result of any outage of the two transformers, the four circuit breakers, and the two cables. The probability that the delivery capacity is 50% is obtained by
  $$P_{50} = 2Q_{transf} + 4Q_{breaker} + 2Q_{cable}$$
- The delivery capacity is 100% when both circuits are available, and the probability of 100% delivery capacity is obtained from
  $$P_{100} = 1 - P_{50} - P_0$$

Bipolar HVDC Connection

A bipolar ±320-kV HVDC connection scheme is shown in Figure 6-4. It was assumed that each transformer, each pole converter, and each pole cable have a rating equal to 50% of the maximum wind farm capacity. Permission for temporary operation with a DC ground current is allowed for the bipolar HVDC connection without a metallic return.

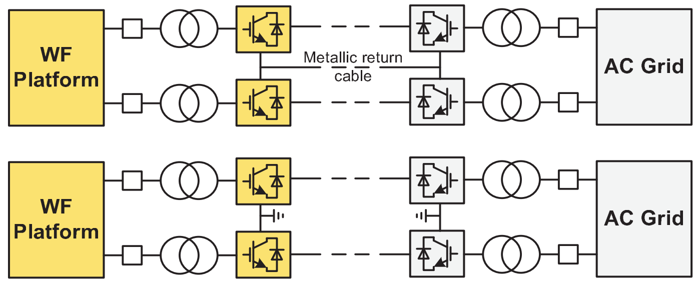


Figure 6-4. Bipolar HVDC connections

The probability of delivery capacity of the bipolar HVDC connection is calculated as follows:

- The delivery capacity is zero when both poles are unavailable as a result of an overlapping outage or common mode failure, and the probability of zero delivery capacity was obtained by
  $P_0 = (2Q_{transf} + 2Q_{conv} + 2Q_{breaker} + Q_{cable})^2 + 2Q_{CMF\text{-}DC} + 2Q_{CMF\text{-}C\&P}$
- The delivery capacity is 50% when one of the two poles is unavailable as a result any outage of the four transformers, the four converters, the four circuit breakers, and the two cables. The probability that the delivery capacity is 50% was obtained by
  $P_{50} = 4Q_{transf} + 4Q_{conv} + 4Q_{breaker} + 2Q_{cable}$
- The delivery capacity is 100% when both poles are available, and the probability of 100% delivery capacity was obtained from
  $P_{100} = 1 - P_{50} - P_0$

Results of Reliability Calculations

Table 6-18 shows the calculated availability of the delivery capacitor for the point-to-point HVAC and HVDC connections.

Table 6-19 shows the risk of production loss of the two point-to-point connections, measured by EENS in MWh per year. The offshore wind farm was assumed to have an annual CF of 40% and an energy production duration curve as shown in Figure 6-5.

Table 6-18. Availability of Delivery Capacity for the Two Point-to-Point Connections

Wind Energy Delivery Capacity	Double-Circuit HVAC		Bipolar HVDC	
	h/yr	%	h/yr	%
0%	5.6	0.6	13.6	0.16
50%	443.7	5.07	626.6	7.15
100%	8,311	94.87	8,120	92.69

The results showed that the reliability of the double-circuit HVAC connection is higher than that of the bipolar HVDC connection. This is because the HVDC delivery system involved more components (converters and onshore transformer) than the HVAC delivery system. The dominating contribution to the unavailability of delivery capacity and the risk of production loss was the outage of submarine cables. In the calculations for the HVAC connection, the forced outage of the reactive compensation equipment was not considered. If power-electronics-based reactive compensators (such as static

Table 6-19. Reliability of the Two Point-to-Point Connections

EENS	Double-Circuit HVAC	Bipolar HVDC
MWh/yr	23456	35315
% of total production	0.70%	1.05%

compensators or static var controllers) were required at the platform and onshore substation, the difference in EENS indices between the HVAC and the HVDC connections would be smaller.

The reliability of a single-circuit HVAC connection and symmetric monopole HVDC connection can be performed using a similar approach. It can be that expected the overall reliability of a single-circuit HVAC system would be higher than that of symmetric monopole HVDC system.

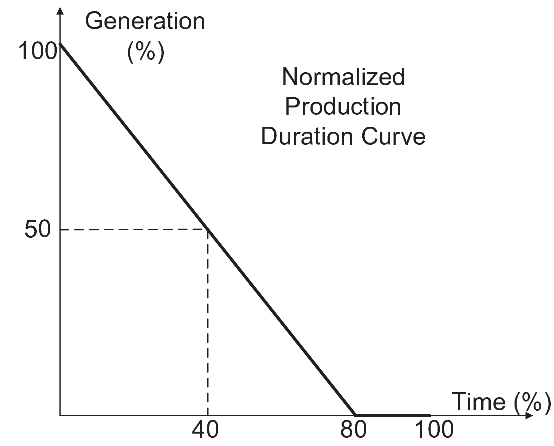


Figure 6-5. Wind farm production duration curve

6.2.3 OFFSHORE DELIVERY SYSTEMS

Several arrangements are available for future offshore grid infrastructure, including radial connections, split connections, backbone connections, and grid connections. Each was considered from a reliability perspective.

Radial Connections

A radial connection involves a single delivery path from an offshore wind farm or a central hub to shore. The study approach and results for basic point-to-point connections apply to the radial connections, assuming that the outages of short connection cables among individual wind farms and the hub are ignored or considered in the reliability calculation for wind collection systems.

Split Connections

The split connection is a connection of a single wind farm or a hub to multiple onshore points. Figure 6-6 shows a split HVAC connection that connects a wind farm to two onshore points. The two HVAC cables may have different ratings. The wind power may be delivered to either or both PCC1 and PCC2, and at low wind generation conditions economic power transfer between PCC1 and PCC2 is feasible.

The probability of delivery capacity from wind farm to shore was calculated as follows.

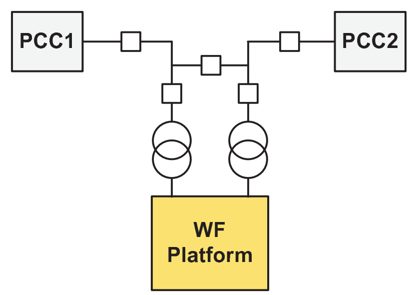


Figure 6-6. Offshore wind farm delivery system with split HVAC connection

Case 1: Each HVAC cable has a rating equal to the wind farm capacity.

- Delivery capacity = 0 MW when WF-PCC1 and WF-PCC2 paths were unavailable
  $P_0 = (Q_{transf} + 2Q_{breaker} + Q_{cable\text{-}PCC1}) * (Q_{transf} + 2Q_{breaker} + Q_{cable\text{-}PCC2})$
- Delivery capacity = 100% of WF capacity
  $P_{100} = 1 - P_0$

Case 2: The HVAC paths from WF to PCC1 and PCC2 have a rating equal to 70% and 50% of the wind farm capacity, respectively.

- Delivery capacity = 0 MW when WF-PCC1 and WF-PCC2 paths were unavailable
  $P_0 = (Q_{transf} + 2Q_{breaker} + Q_{cable\text{-}PCC1}) * (Q_{transf} + 2Q_{breaker} + Q_{cable\text{-}PCC2})$

- Delivery capacity = 50% of WF capacity when WF-PCC1 or one main transformer circuit at WF was unavailable
  $P_{50} = (Q_{transf} + 2Q_{breaker} + Q_{cable\text{-}PCC1}) + (2Q_{transf} + 2Q_{breaker})$

- Delivery capacity = 70% of WF capacity when WF-PCC2 was unavailable
  $P_{70} = Q_{transf} + 2Q_{breaker} + Q_{cable\text{-}PCC2}$

- Delivery capacity = 100% of WF capacity
  $P_{100} = 1 – P_0 – P_{50} – P_{70}$

Figure 6-7 shows a split HVDC connection that connects a wind farm to two onshore points. The two separate HVDC links may have different ratings. The wind power may be delivered to either or both the PCC1 and PCC2. However, power transfer between PCC1 and PCC2 may not be economically feasible as a result of high conversion losses.

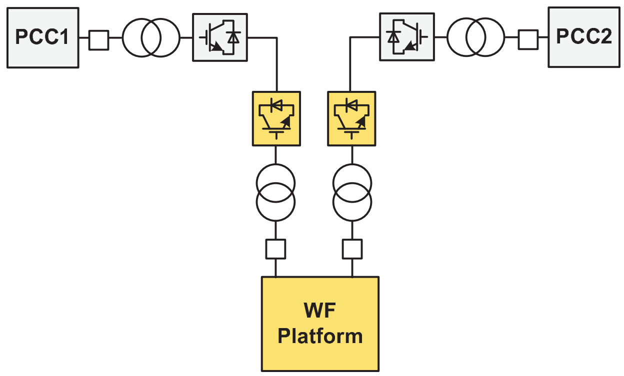


Figure 6-7. Offshore wind farm delivery system with separate HVDC links

Figure 6-8 shows a three-terminal HVDC connection that connects a wind farm to two onshore points. The two HVDC cables may have different ratings. The wind power may be delivered to either or both the PCC1 and PCC2, and at low wind generation conditions, economical power transfer between PCC1 and PCC2 is feasible.

In the following, the delivery capacity of the three-terminal HVDC connection is discussed.

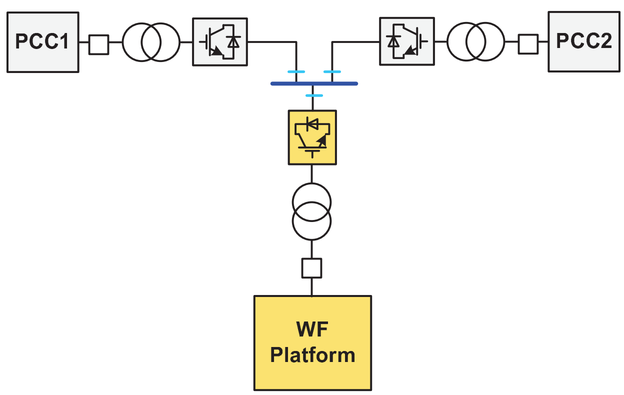


Figure 6-8. Three-terminal HVDC offshore wind farm delivery system

Case 1: Each HVDC cable has a rating equal to the wind farm capacity.

- Delivery capacity = 0 MW when WF-PCC1 and WF-PCC2 paths or any platform main conversion and transformation components were unavailable
  $P_0 = (Q_{conv} + Q_{transf} + Q_{breaker} + Q_{cable\text{-}PCC1}) * (Q_{conv} + Q_{transf} + Q_{breaker} + Q_{cable\text{-}PCC2}) + (Q_{conv} + Q_{transf} + Q_{breaker} + Q_{dc\text{-}bus})$

- Delivery capacity = 100% of WF capacity
  $P_{100} = 1 – P_0$

Case 2: The HVAC paths from WF to PCC1 and PCC2 have a rating equal to 70% and 50% of the wind farm capacity respectively.

- Delivery capacity = 0 MW when WF-PCC1 and WF-PCC2 paths or any platform main conversion and transformation components were unavailable
  $P_0 = (Q_{transf} + Q_{breaker} + Q_{cable\text{-}PCC1}) * (Q_{transf} + Q_{breaker} + Q_{cable\text{-}PCC2}) + (Q_{conv} + Q_{transf} + Q_{breaker} + Q_{dc\text{-}bus})$
- Delivery capacity = 50% of WF capacity when WF-PCC1 was unavailable
  $P_{50} = Q_{transf} + Q_{transf} + Q_{breaker} + Q_{cable\text{-}PCC1}$
- Delivery capacity = 70% of WF capacity when WF-PCC2 was unavailable
  $P_{70} = Q_{transf} + Q_{transf} + 2Q_{breaker} + Q_{cable\text{-}PCC2}$
- Delivery capacity = 100% of WF capacity:
  $P_{100} = 1 – P_0 – P_{50} – P_{70}$

Backbone Connections

As shown in Figure 6-9, a backbone interconnects multiple offshore wind platforms in a continuous chain and delivers the aggregated wind power to multiple onshore points. This would be a logical development from multiple radial systems if they were built or planned along a section of shoreline.

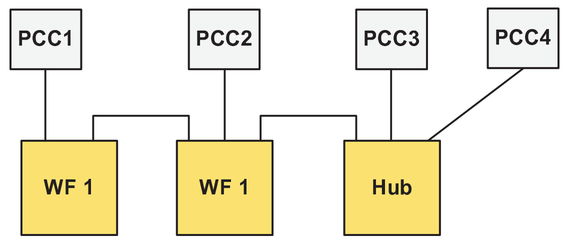


Figure 6-9. Offshore wind backbone delivery system

An HVAC offshore grid system would require reactive compensation equipment in the middle of long-distance connections. This will significantly increase the overall cost of an offshore grid delivery system. The benefits of an HVAC grid connection compared to radial HVAC connections are limited, because the delivery of wind power to the onshore interconnection points are based primarily on system impedance. An HVDC offshore grid system demonstrates greater flexibility than an HVAC offshore grid system, because the power flow amount and direction can be effectively controlled by onshore converters [9]. With backbone delivery systems, economic power transfer among onshore points is feasible at low wind generation conditions. In fact, so far the proposed and planned backbone offshore wind delivery systems in the industry are all based on HVDC technologies.

It is likely that single-element (N-1) contingencies will be considered in the design of backbone HVDC delivery systems, so the overall delivery capacity from wind farm platforms to the power grid onshore would be affected only by high-order outage events. A detailed reliability study that considers the overlapping forced and maintenance outages using the appropriate simulation tools could be conducted, but this is beyond the purposes of the current study.

The overall delivery capacity of a backbone delivery system could be determined based on the total capacity of rated wind farms. In this case, the delivery capacity of a backbone system and the risk of production loss will be constrained during N-1 contingencies. However, a constrained delivery capability has impacts only during the simultaneous peak generation hours of connected wind farms. As such, the overall risk of a backbone delivery system concerning wind generation loss would be significantly lower than that of radial connections.

Grid Connections

An offshore grid delivery system would involve the interconnection of multiple farms or hubs offshore and provide multiple connections onshore, as shown in Figure 6-10. Technically, a backbone would be a form of offshore grid; however, more complex interconnections among the delivery platforms were contemplated in this case.

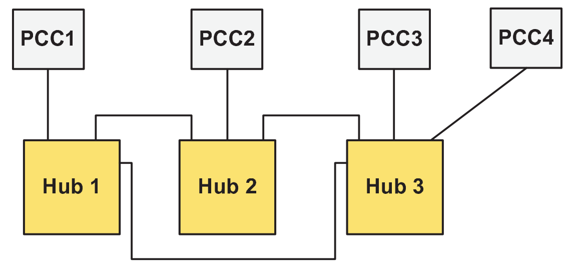


Figure 6-10. Offshore wind grid delivery system

Similar to backbone connections, the offshore wind grid delivery systems that have been considered in the industry are also based on HVDC technologies. Grid connections can provide further increased reliability and flexibility of the offshore power delivery system.

Single-element (N-1) contingencies will be considered in the design of such a grid delivery system, so the overall delivery capacity from wind platforms to the power grid onshore would be affected only by high-order outage events.

6.2.4 RELIABILITY OF COLLECTION SYSTEMS

The reliability of collection systems was also evaluated. The outage statistics of the main components of collection systems, the reliability performance of feeder collection systems for an example large offshore wind farm, and the reliability performance of cluster collection systems for a medium offshore wind farm were all considered.

Outage Statistics for Reliability Calculations

Table 6-20 summarizes the outage statistics of the main components for the reliability calculations of wind turbine collection systems as described in [14], [15], [16] [17].

In general, failure rates of circuit breakers and converters are the same for platform and wind tower installations, but the failure durations of wind tower components are longer than those of platform components because of access limitations to the wind towers.

The failure rates of AC/DC or DC/AC converters are 50% for full power converters; whereas the failure durations of AC/DC or DC/AC converters are the same as those for full power converters.

Finally, failure rates and durations of medium-voltage alternating-current (MVAC) and medium-voltage direct-current (MVDC) submarine cables are the same.

Table 6-20. Outage Statistics for Wind Turbine Collection Systems

Collection System	Failure Rate (1/yr)	Repair Time (h)	Main. rate (1/yr)	Main Time (h)
Platform S/S				
Main transformer	0.024	2160	0.25	40
MVAC breaker	0.025	144	0.25	24
MVDC breaker	0.025	144	0.25	24
MV bus bar	0.005	144		
Full power converter	0.2	144	0.5	24
DC/AC converter	0.1	144	0.5	12
MV Cable				
1-km MVAC CBL	0.015	1,440		
1-km MVDC CBL	0.015	1,440		
WTG (Tower)				
Generator	0.1	240	0.25	24
Transformer	0.0131	240	0.25	24
AC breaker	0.025	240	0.25	24
DC breaker	0.025	240	0.25	24
Full-power converter	0.2	240	0.5	24
AC/DC converter	0.1	240	0.5	12

6.2.5 Feeder Collection Systems

The example wind farm consists of 96 5-MW wind turbines, which gives a total installed power of 480 MW. These 96 wind turbines are divided into 12 radial connections—one for each row, as shown in Figure 6-11. The distances between two wind turbines in a radial connection, between the radial connections, and between the platform and the central feeder are all 1 km.

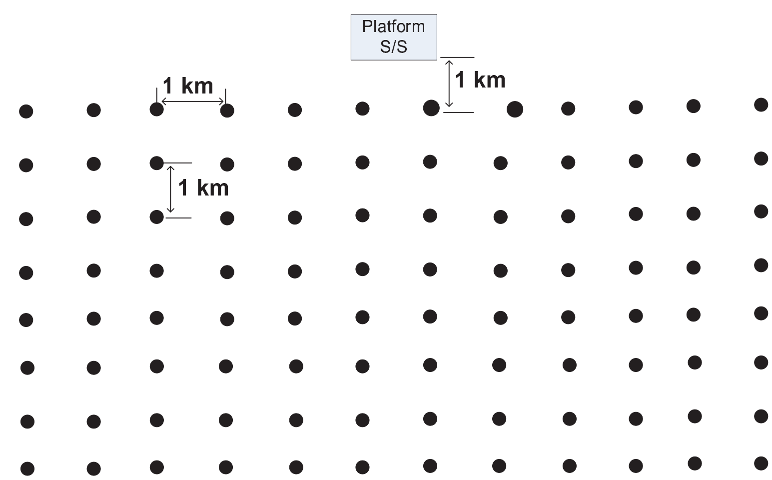


Figure 6-11. Layout of the example wind farm

Collection System Topologies

The feeder collection topologies considered in this study include radial, bifurcated radial, single-sided ring, and double-sided ring, as shown in Figure 6-12.

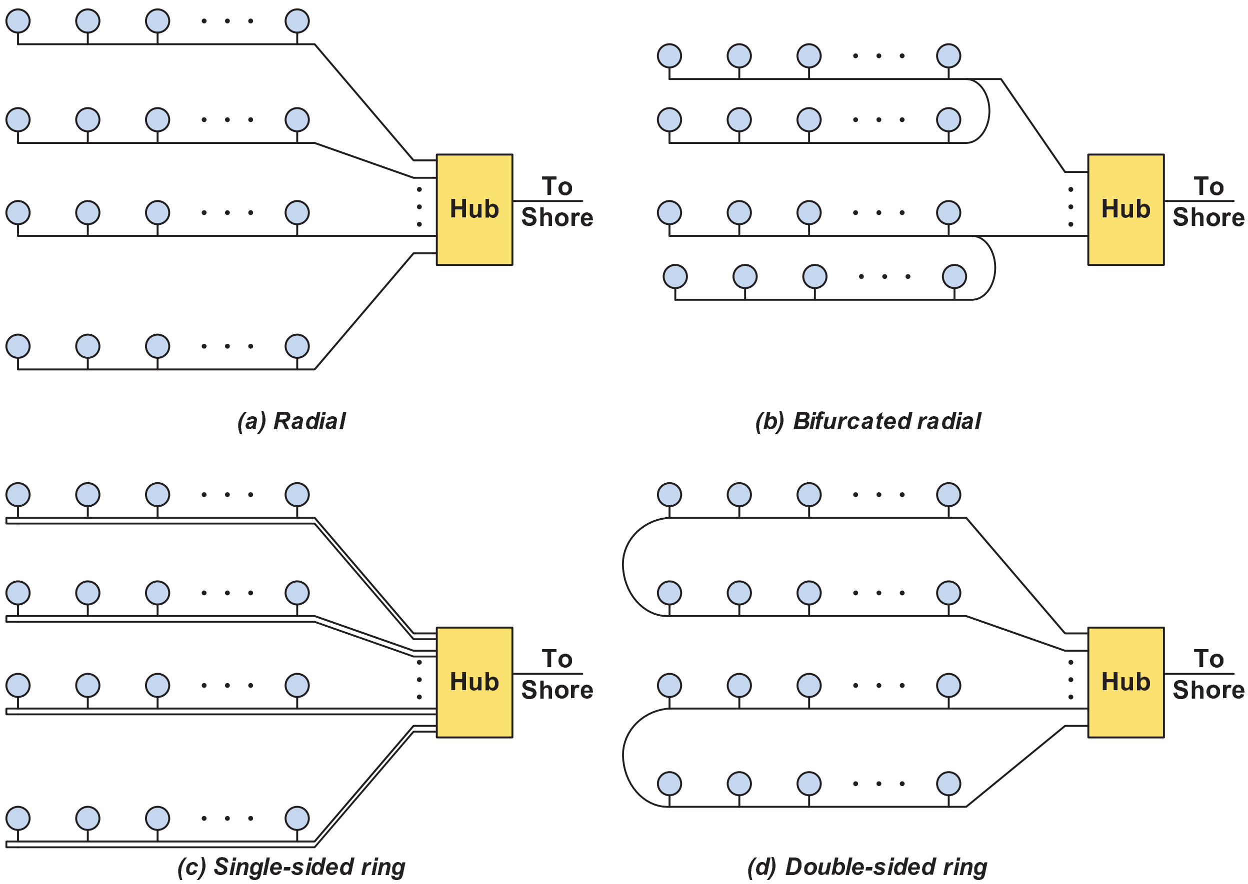
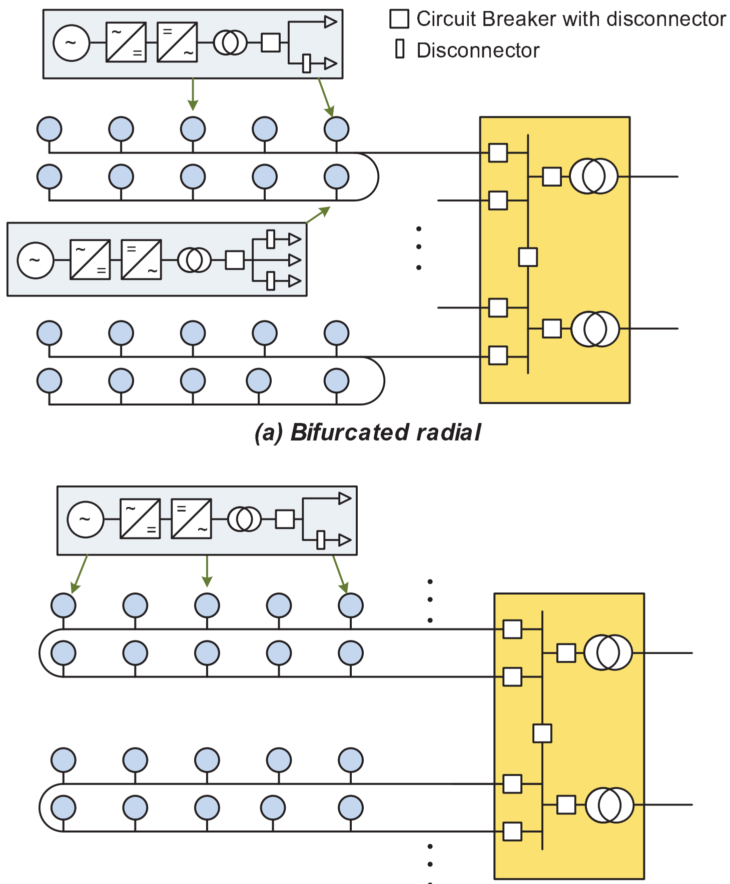


Figure 6-12. Typical topologies of feeder collection systems

Reliability Calculations

Figure 6-13 shows the switchgear assumed for a medium-voltage collector system. Four outage levels are possible, as described below:

- Turbine outage—The loss of one turbine resulting from the failure of the main drivetrain equipment (generator, converter, and transformer) on the wind tower
- Multi-turbine outage—The loss of multiple turbines connected to the same feeder section resulting from the failure of the feeder section cable or turbine switchgear
- Feeder outage—The loss of all turbines connected to the same feeder resulting from the failure of the feeder cable, turbine switchgear, or feeder breaker at the platform
- Multi-feeder outage—The loss of multiple feeders resulting from the failure of the main transformer, transformer breaker, or bus section at the platform



(a) Bifurcated radial

(b) Double-sided ring

Figure 6-13. Switchgear arrangements for MVAC collection systems

In the reliability calculation, second-order outage events (i.e., N-2 contingencies) and transient power interruptions were omitted, and it was assumed that all disconnectors at the wind turbines are remotely controlled. It was also assumed that all cable sections in ring-collection topologies had ratings capable of handling the full production of the ring.

Results of Reliability Calculations

Table 6-21 shows the calculated EENS of a feeder turbine collection system. In the calculation, it was assumed that the example offshore wind farm has an annual CF of 40%.

The results indicate that the reliability of ring topologies is higher than that of radial feeder topologies because of the redundancy of cable circuits in the ring topologies. For ring topologies, wind turbines connected to a faulted feeder or feeder section can quickly resume normal operation after the fault is isolated by switching devices. If transient power interruption is ignored, the EENS indices for the two radial topologies and the two ring topologies would be the same, respectively. The dominating contribution to the power output loss is the outage of feeder cables. Table 6-22 shows the impact of cable repairing durations on the EENS of radial topologies.

Table 6-21. Reliability of Feeder Wind Turbine Collection Systems

EEENS (MWh/yr)				
Outage Type	**Radial**	**Bifurcated Radial**	**One-Sided Ring**	**Double-Sided Ring**
Wind turbine outage	15,580	15,580	15,580	15,580
Multi-wind turbine outage	14,515	16,589		
Feeder outage	15,206	13,133		
Multi-feeder outage	10,783	10,783	10,783	10,783
Total	56,084	56,084	26,362	26,362
% of production	3.33%	3.33%	1.57%	1.57%

Table 6-22. Impacts on EENS by Feeder Cable Repairing Time

EENS (MWh/y)	Radial	Bifurcated Radial	One-Sided Ring	Double-Sided Ring
Cable, r_A =1440 h	3.61%	3.61%	1.84%	1.84%
Cable, r_A = 720 h	2.75%	2.75%	1.84%	1.84%
Cable, r_A = 288 h	2.23%	2.23%	1.84%	1.84%

6.2.6 CLUSTER COLLECTION SYSTEMS

Cluster collection architectures allow for the flexible placement of wind turbines in the geographical landscape. This design concept offers the opportunity to eliminate the wind turbine transformers and place converters at the cluster platform. In this subsection, the reliability performance of cluster collection systems is evaluated for an example offshore wind farm.

Collection System Topologies

The example wind farm consists of 18 5-MW wind turbines, which gives a total installed power of 90 MW. With a conventional feeder collection system design, the 18 turbines are arranged in three feeders (see Figure 6-14), which equals 6 turbines and 30 MW per feeder.

Figure 6-15 shows the four-cluster collection system architectures without wind turbine transformers.

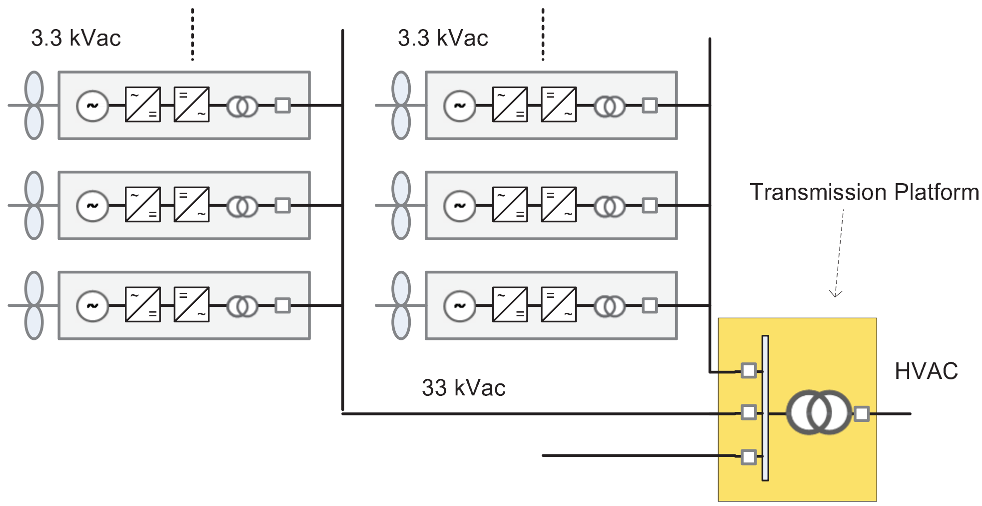


Figure 6-14. Feeder wind turbine collection system

- MVAC cluster-1—6~13.8-kV AC cluster without turbines transformers
- MVAC clsuter-2—6~13.8-kV AC cluster with converter on the cluster platform
- MVDC cluster-1—10~24-kV DC cluster with inverters on the cluster platform
- MVDC cluster-2—10~24-kV DC cluster with single inverter on the cluster platform

In each of these system architectures, the 18 turbines were arranged in two clusters so that 9 turbines were connected to each cluster platform and the cluster power level was 45 MW. The cluster platform either coincided with or was next to the middle wind tower of the cluster.

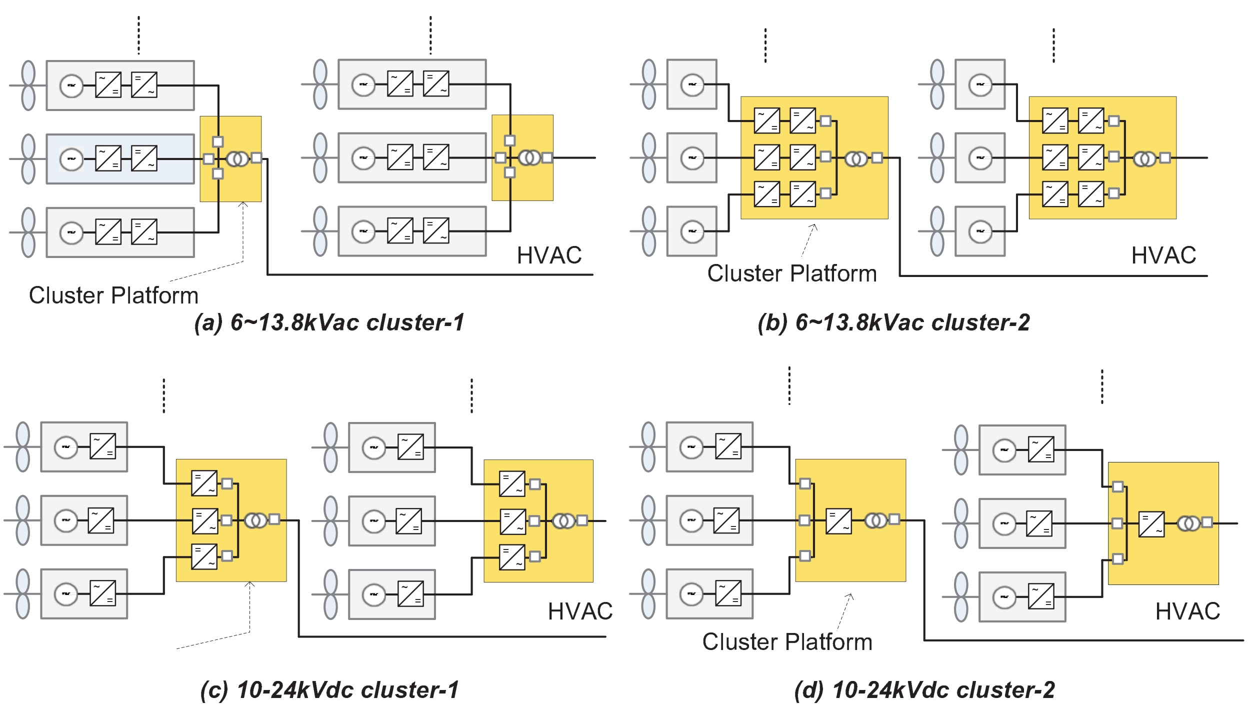


Figure 6-15. Cluster wind turbine collection systems

Reliability Calculations

The reliability assessment considered power output losses that resulted from both forced and maintenance outages; overlapping events of forced outages were ignored. Depending on the system architectures, four outage levels were possible:

- Wind turbine outage (5 MW)
- Feeder outage (30 MW)
- Cluster outage (45 MW)
- Plant outage (90 MW)

Three outage levels occurred for the system architecture with feeder collection design: turbine outage, feeder outage, and plant outage. A turbine outage is triggered by the failure of any component on the wind tower. A feeder outage is triggered by the failure of any cable section or the failure of the feeder circuit breaker. The failure of a turbine circuit breaker also triggers a feeder-level outage. A plant-level outage is caused by the failure of the main transformer, collection bus, or feeder circuit breaker. Only two outage levels occurred for the cluster collection architectures: turbine outage and cluster outage, triggered by the failure of any component on the wind tower and between the turbine and the collection bus on the platform. A cluster level outage is associated with the failure of the main transformer or platform bus. It could also be triggered by the failure of a turbine circuit breaker.

Results of Reliability Calculations

Table 6-23 shows the EENS indices of different wind turbine collection systems. The calculations assumed that the study wind farm has an annual CF of 40%.

The following observations were made based on the results:

- The reliability of cluster wind turbine collections is higher than that of the feeder collection. The EENS contributed by forced outages was reduced by 45% to 52%, and the EENS contributed by maintenance outages was reduced by 23%.
- The reduction of EENS is mainly a result of the elimination of feeder-level outages, because each turbine is connected to the cluster platform by an individual cable and circuit breaker.
- The reduced repairing time of the power converters, which are located at the cluster platform, also contributed to the additional reduction of EENS.

Table 6-23. Reliability of Feeder Wind Turbine Collection Systems

Collection Systems	Forced Outage, EENS (MWh/yr)					
	90-MW Loss	45-MW Loss	30-MW Loss	5-MW Loss	Total	Reduction (%)
MVAC feeder	1,264		3,266	1,826	6,356	
AC Cluster-1		1,264		2,226	3,490	45.1%
AC Cluster-2		1,264		1,794	3,058	51.9%
DC Cluster-1		1,264		2,010	3,274	48.5%
DC Cluster-2		1,588		1,686	3,274	48.5%
Maintenance Outage, EENS (MWh/y)						
MVAC feeder	360		135	675	1,170	
AC Cluster-1		360		540	900	23.1%
AC Cluster-2		360		540	900	23.1%
DC Cluster-1		360		540	900	23.1%
DC Cluster-2		495		405	900	23.1%
Total Outage, EENS (MWh/y)						
MVAC Feeder	1,624		3,401	2,501	7,526	
AC Cluster-1		1,624		2,766	4,390	41.7%
AC Cluster-2		1,624		2,334	3,958	47.4%
DC Cluster-1		1,624		2,550	4,174	44.5%
DC Cluster-2		2,083		2,091	4,174	44.5%

6.2.7 *RELIABILITY ASSESSMENT CONCLUSIONS*

The reliability and risk assessment evaluated the basic reliability characteristics of offshore wind electrical system systems and concluded the following.

Basic HVDC and HVAC Connections

The reliability of an HVAC connection would be higher than that of an HVDC connection, with a 30% difference in the estimated EENS indices in the example case study. The unavailability of delivery capacity and the risk of production loss result primarily from the outage of submarine cables. If power electronic reactive compensators are required for HVAC connections, the difference in EENS indices between HVAC and HVDC connections would become comparable.

Offshore Delivery Systems

Radial and split delivery systems may be implemented with either HVAC or HVDC technologies. The study approach and results for basic HVAC and HVDC connections were applied to the split connections. It is anticipated that the backbone and grid delivery systems would be developed based on HVDC technologies. The risk of production loss of a backbone delivery system would be significantly lower than that of radial connections. Single-element (N-1) contingencies are expected to be considered in the design of a grid delivery system, so the overall delivery capacity would be affected only by high-order outage events.

Wind Farm Collection Systems

Radial feeder collection topologies are typically used for large offshore wind farms. The reliability of ring topologies would be higher than that of feeder topologies, with a 50% difference in the estimated EENS indices in the example case study. For installations in which lower durations are expected for feeder cable repairs, the difference in EENS indices between the ring and feeder topologies would become comparable. For medium wind farms, cluster collection architectures offer improved reliability than the conventional feeder collection architecture.

6.3 Preliminary Topology Comparisons

The next step in the study process was to conduct a high-level assessment of the potential performance of various offshore wind delivery systems and their potential impacts to the onshore grid. Because of the large number of possible configurations, this assessment was limited in scope and only considered issues in a general manner. The ultimate performance and system impacts of actual installations will be highly specific to site selection and design and will depend on factors such as the onshore grid characteristics, selected interconnection points, actual capacities of the wind farms, and design of the ultimate delivery system. Nevertheless, useful information can be gained by performing the preliminary assessments described below.

In this assessment, the performance and system impact of various offshore wind delivery system options was assessed from a steady-state perspective using power flow analyses during normal and contingency conditions. The study area was the entire PJM, focusing on the transmission system at 230 kV and above, which was monitored for thermal (overload) issues. In the initial study efforts, with a large amount of offshore wind generation interconnected to the onshore system, thermal issues were of prime importance, because they relate to the ability to transfer a significant amount of power through large regions. From the perspective of power system transmission planning, it is necessary to first identify needed system upgrades to mitigate such thermal violations, with future work assessing impacts on network voltages and the need for any additional system upgrades.

Comparisons were made among the different technologies (HVAC versus HVDC) and different topologies (radial, backbone, or grid). The Siemens' Power System Simulator for Engineering and DigSILENT's PowerFactory tools were used for this study.

6.3.1 Study Model Development and Assumptions

For this evaluation, ISO-NE's power flow for 2030 summer peak conditions [18] was selected as the base case. This year is consistent with the last year considered for the development of 54 GW as described in the previous sections. The power flow case represents the Eastern Interconnection, including the areas of New England and PJM that have the largest concentration of projected 2030 offshore wind installations.

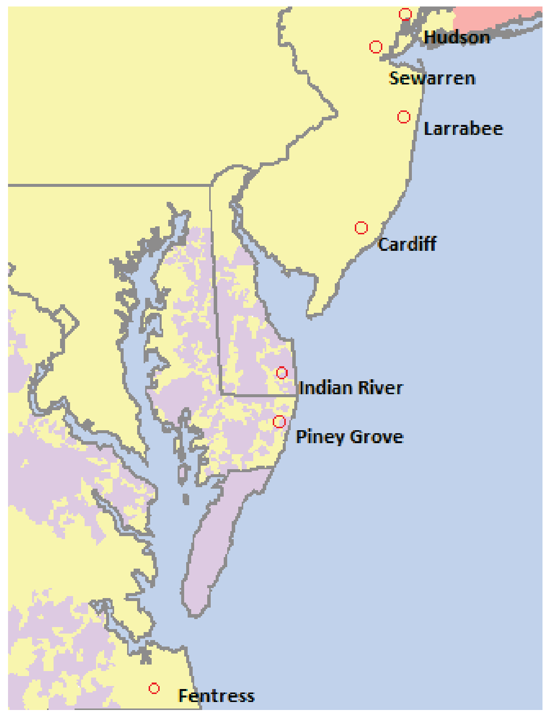


Figure 6-16. Onshore interconnection substations

<u>*Offshore Wind Generation*</u>

This evaluation focused on the PJM planning area. Seven hypothetical offshore wind farms with 1,000 MW installed capacity each were assumed and connected to the following substations:

- Hudson 230-kV substation
- Sewaren 230-kV substation
- Larrabee 230-kV substation
- Cardiff 230-kV substation
- Indian River 230-kV substation
- Piney Grove 230-kV substation
- Fentress 230-kV substation

All of the wind farms were assumed to be located 30 mi from the nearest interconnecting substation. The average distance to shore among the 207 sites identified in Section 3.0 was approximately 23 mi (37 km), but a direct run for the cables to shore is very unlikely, and the substations will not be directly on the coast. Thus, 30 mi was considered a more appropriate distance.

Two generation scenarios were considered for the wind farms, as described below and summarized in Table 6-24.

Table 6-24. Wind Generation Output Scenarios

Nearest Onshore Interconnection Substation	Evenly Spread Generation (MW)	Unevenly Spread Generation (MW)
Hudson	500	0
Sewaren	500	0
Larrabee	500	500
Cardiff	500	500
Indian River	500	500
Piney Grove	500	1,000
Fentress	500	1,000
Total	3,500	3,500

- **Offshore wind evenly spread**—Each wind farm was assumed to output 50% of its capacity (i.e., 500 MW). The total offshore generation from the seven wind farms was 3,500 MW.
- **Offshore wind unevenly spread**—The output of the two southernmost wind farms was assumed to be 100% of their capacity; whereas the output of the two northernmost wind farms was assumed to be 0%. The remaining farms' output was maintained at 50%. This arrangement kept

the total offshore wind generation at 3,500 MW and permitted a useful comparison of the results between the two scenarios.

In both scenarios, the generation from the offshore wind was accommodated by scaling down the generation from peaking units in the PJM.

Assuming a distance of only 30 mi between the wind farms and the onshore interconnection substations, HVAC delivery systems are generally more economical than HVDC systems for radial connections. To evaluate the HVAC option, double-circuit 230-kV AC cables with 2,000-kcmil cross sections were assumed. This allows a normal operating capacity of approximately 1,076 MW for each radial connection. Figure 6-17 shows the offshore wind delivery system with a radial connection and the wind generation spreading evenly.

An HVDC radial delivery system will show similar performance and will have similar impacts to the onshore system, but it is expected to be significantly more expensive because of the need for converter stations. As the wind power plants are moved farther from shore, HVDC systems may become more economical than HVAC systems because of the need to address the cable charging by a combination of reactive compensation and additional cables.

Building on the concept of an HVAC radial connection, offshore substations could be connected together to create an offshore backbone connection structure (Figure 6-18 (a)). To evaluate this option, double-circuit 230-kV AC cables with 2,000-kcmil cross sections were assumed to provide a 1,076-MW transfer capacity between any two connected substations. As described in Section 5.6.4, the cable-charging currents associated with AC systems can impact the transfer capability of the systems. The high charging current for long cables can reduce the cable’s capability to transfer real power and also result in high voltages at the connected substations. To reduce these negative effects, it is assumed that reactive compensation reactors are applied in the middle of HVAC connections longer than 50 mi. An additional platform for the reactive compensation equipment would be required at each of these locations.

Using the same general topology of the HVAC backbone connection, an offshore HVDC backbone connection was developed using DIgSILENT. Bipole VSC HVDC converters were assumed to provide 1,000-MW transfer capacity between any two connected substations. Figure 6-18 (b) shows the offshore wind delivery system with an HVDC backbone connection.

Examples of detailed models of the Hudson onshore and offshore HVDC converter substations are shown in Figure 6-19 and Figure 6-20, respectively.

The backbone structure can be enhanced to create an offshore grid structure. This was done by again assuming that double-circuit 230-kV AC cables with 2,000-kcmil cross sections providing 1,076-MW transfer capacities are connected between substations. Figure 6-21 (a) shows the offshore wind delivery system with an HVAC grid connection. This particular offshore grid structure is essentially composed of two backbone structures connected together at each end to create an offshore grid.

To reduce the negative effects of the HVAC cable-charging current, it is assumed that reactive compensation reactors are applied in the middle of the HVAC connections longer than 50 mi, which results in additional platforms and their associated costs.

An offshore HVDC grid connection system having the same general topology as the HVAC grid was developed using DIgSILENT. Bi-pole VSC HVDC converter stations were again assumed to provide a 1,000-MW transfer capacity between any two connected substations. Figure 6-21 (b) shows the offshore wind delivery system with an HVDC backbone connection.

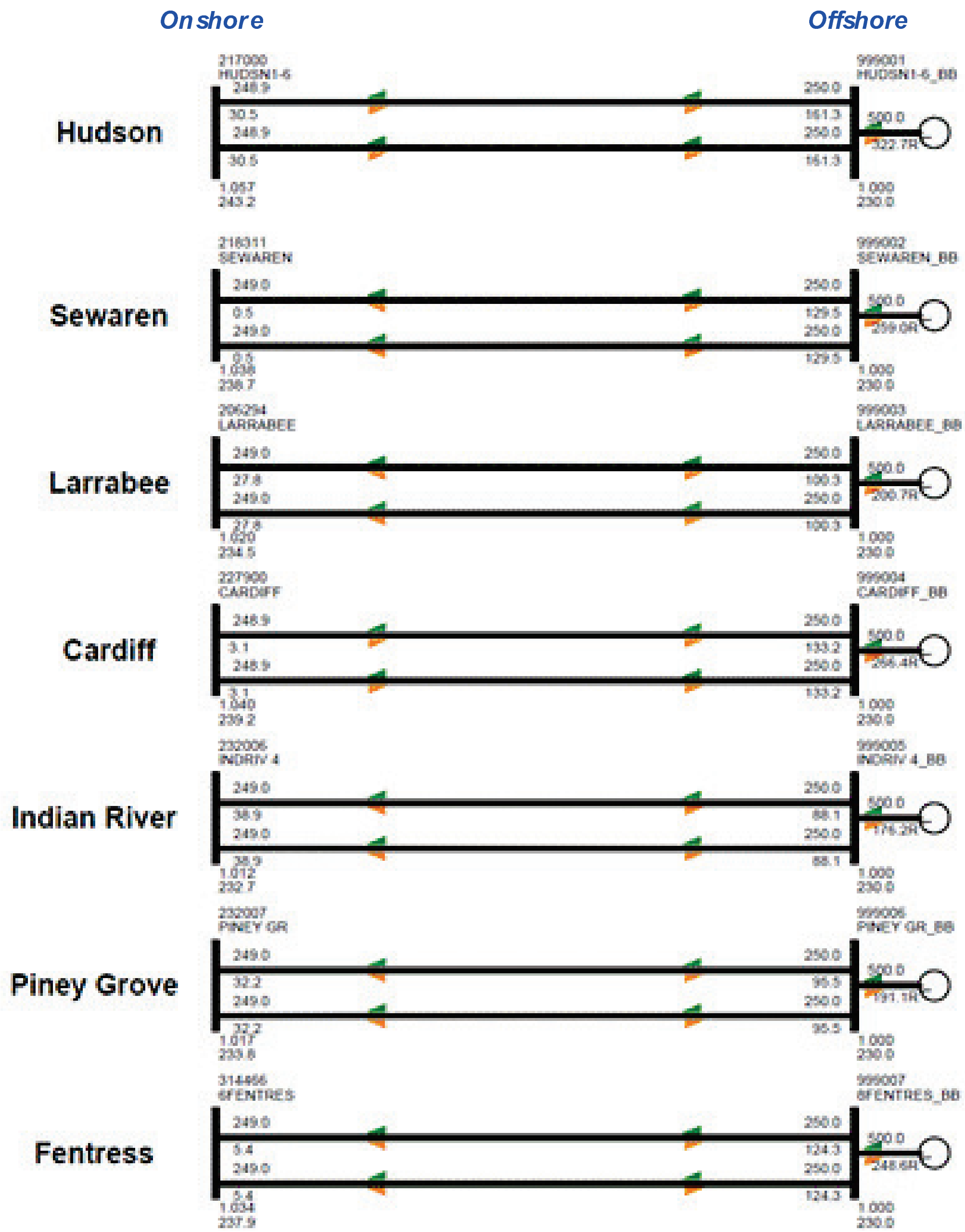
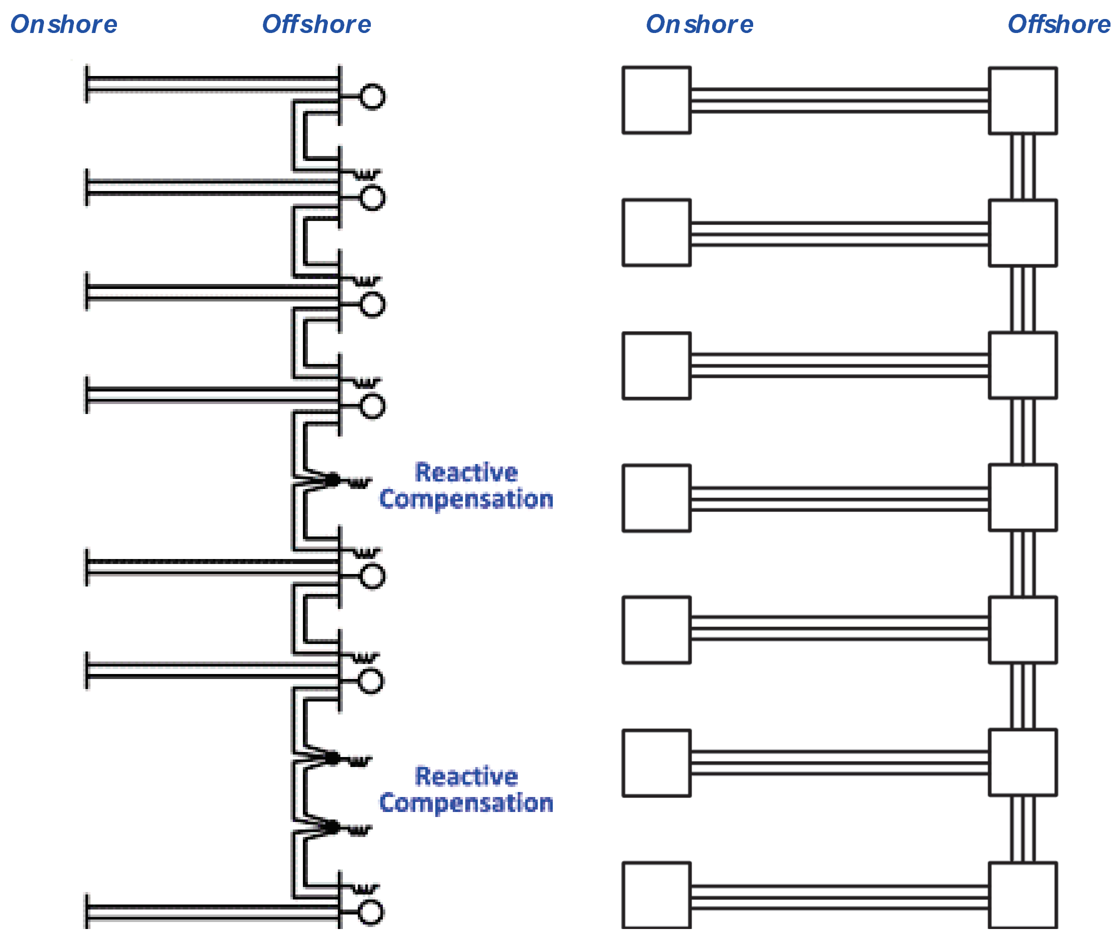


Figure 6-17. Offshore wind delivery system—radial connection with evenly spread wind generation



(a) HVAC (b) HVDC

Figure 6-18. Offshore wind delivery system—backbone connection

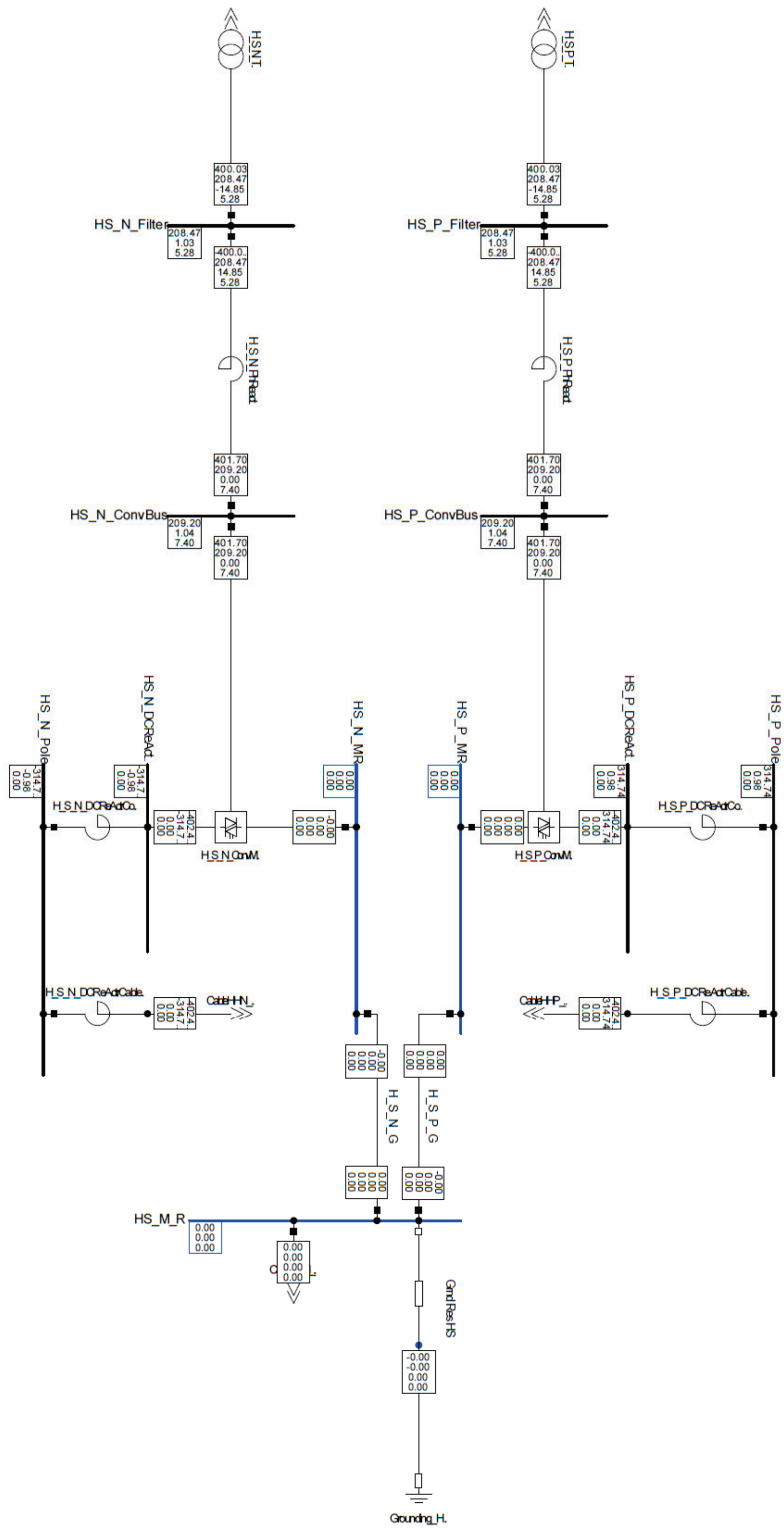


Figure 6-19. Hudson onshore HVDC converter station

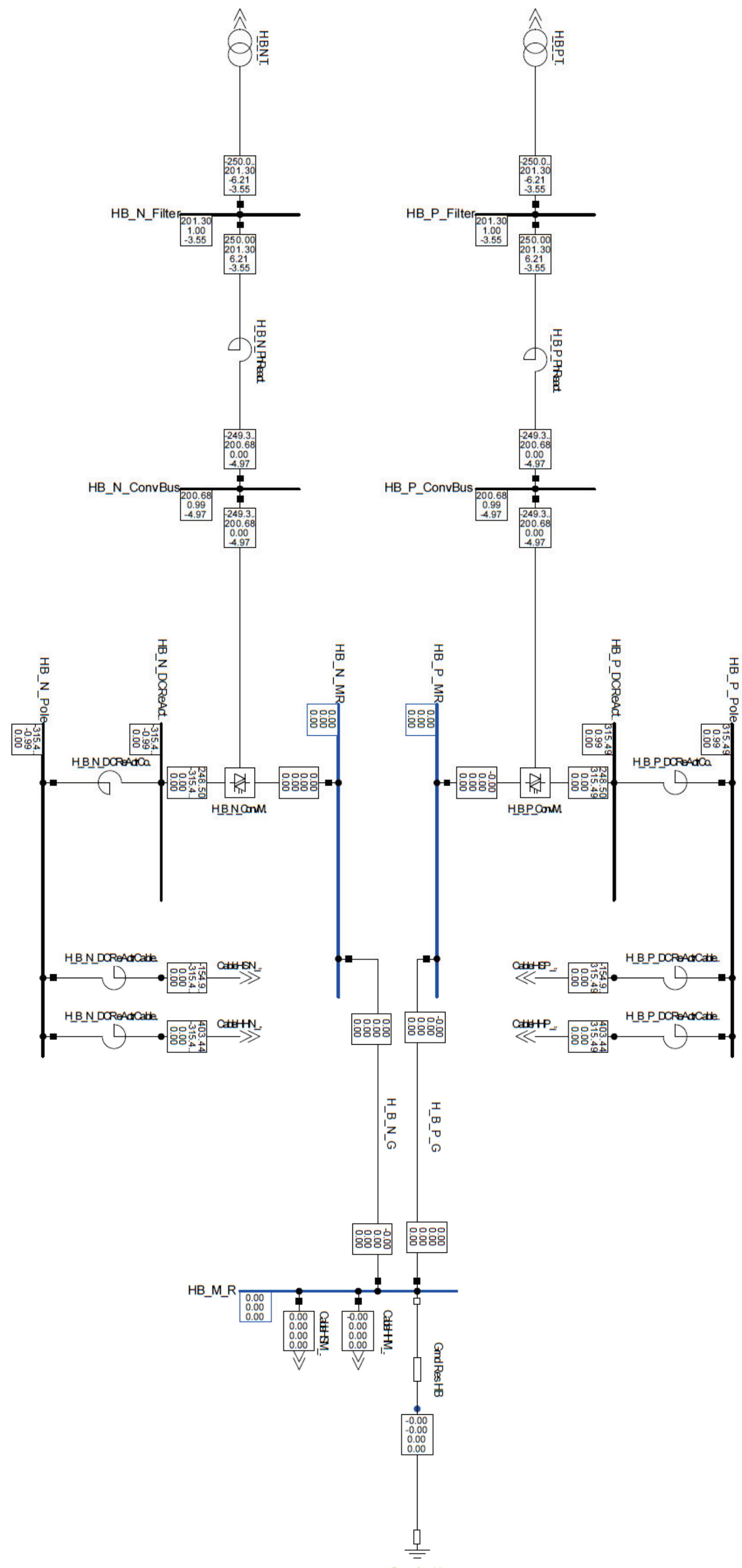
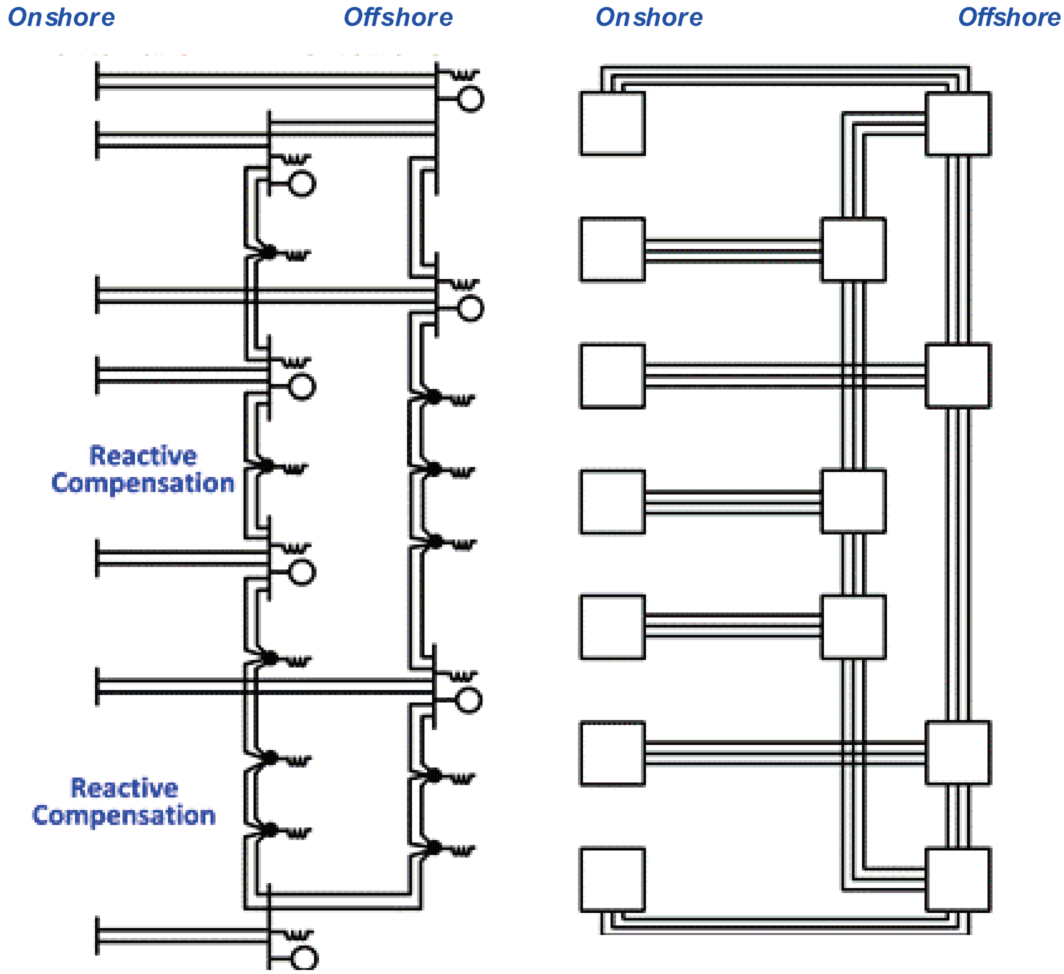


Figure 6-20. Hudson onshore HVDC converter station



(a) HVAC (b) HVDC

Figure 6-21. Offshore wind delivery system—grid connection

6.3.2 Offshore Wind Delivery System Performance and Onshore System Impact

Power flow simulations with no contingencies and single contingencies (N-1) on the 230-kV and higher voltage system were performed for the base case and each of the offshore wind cases previously defined. Single- and parallel-circuit contingencies on the offshore delivery system were also considered for each offshore wind case. The results for each offshore wind case were compared to the base case to identify significant adverse system impacts from the offshore generation interconnection. If any element experiences thermal violations during more than one contingency, only the contingency leading to the worst overload is reported.

New thermal violations caused by adding offshore wind generation are summarized below for each of the study cases.

First, results for the scenario considering offshore wind evenly spread are presented. Table 6-25 shows the power injection at each onshore substation with different offshore delivery topologies for both HVAC and HVDC systems. Also shown in the table are the number of elements that did not experience overloads prior to the addition of the offshore wind, but which experience loading in excess of their reported emergency rating when the offshore wind is connected. There are 21 newly overloaded transmission lines or transformers with radial HVAC offshore delivery systems. With an HVAC backbone or grid delivery system, the total number of newly overloaded elements is reduced to 13 and 12, respectively.

Table 6-25. Power Injection at Each Onshore Substation

Onshore						Offshore	
Substation	HVAC Radial (MW)	HVAC Backbone (MW)	HVAC Grid (MW)	HVDC Backbone (MW)	HVDC Grid (MW)	Substation	Wind Generation (MW)
Hudson	498	710	766	800	800	Hudson	500
Sewaren	498	403	459	900	900	Sewaren	500
Larrabee	498	641	648	300	300	Larrabee	500
Cardiff	498	595	596	275	275	Cardiff	500
Indian River	498	159	94	200	200	Indian River	500
Piney Grove	498	233	140	139	139	Piney Grove	500
Fentress	498	735	773	825	825	Fentress	500
No. of Overloads	21	13	12	6	6		

The 12 overloaded elements (11 transmission lines and 1 transformer) were analyzed to determine their loading sensitivity to the power injection at each of the onshore interconnection substations. Because the power injection at the substation with the HVAC offshore grid is controlled purely by network impedances, the sensitivity evaluation was made by using the HVDC grid, which can directly control the power injection into the onshore system.

With either HVDC system, 6 transmission lines or transformers remained overloaded regardless of the power injection levels. A careful review indicated that these lines are either not sensitive to power injection at any single onshore substation or are very close to an onshore interconnection substation where system upgrades are needed to allow wind generation to enter the onshore system.

The sensitivity results showed that the onshore system congestion (reduced number of the thermal violations) could be mitigated by sending more wind generation to the north through the offshore delivery system. This can be accomplished by using either an HVDC backbone or an HVDC grid. Table 6-25 shows the power injection at each of the onshore interconnection substations and offshore substations that results in the minimum number of overloaded elements using these delivery systems.

Next, the results for the scenario with offshore wind unevenly spread are presented.

Table 6-26 shows the power injection at each onshore substation with different offshore delivery systems. With the HVAC backbone and grid delivery systems, the offshore connections between the Fentress offshore and onshore substations are overloaded during conditions with no contingency (i.e., N-0).

There are 26 newly overloaded transmission lines or transformers in the case with an HVAC radial delivery system. With the HVAC backbone and grid systems, the total number of newly overloaded elements is reduced to 21 and 19, respectively.

With the HVDC backbone delivery system, it is not possible to maintain the same onshore power injection into the substations as was done for the scenario with evenly spread wind generation. Doing so causes some of the offshore backbone paths to become overloaded in an attempt to send too much power to the north. To avoid overloading the offshore circuits while sending as much power as possible to the north, the power injection at each of the onshore interconnection substations was set as shown in Table 6-26.

For the HVDC grid, the power injection at each onshore substation can be maintained as in the scenario with evenly spread wind generation without causing overloads on any offshore grid path.

There are 17 newly overloaded elements with the HVDC backbone delivery system; however, there are only 6 overloaded elements with the HVDC grid system, which is the same as was shown with wind generation spread evenly.

Table 6-26. Power Injection at Each Onshore Substation—HVAC Offshore Delivery System

Onshore						Offshore	
Substation	HVAC Radial (MW)	HVAC Backbone (MW)	HVAC Grid (MW)	HVDC Backbone (MW)	HVDC Grid (MW)	Substation	Wind Generation (MW)
Hudson	0	347	466	400	800	Hudson	0
Sewaren	0	60	170	570	900	Sewaren	0
Larrabee	498	500	547	400	300	Larrabee	500
Cardiff	498	614	574	400	275	Cardiff	500
Indian River	498	258	67	400	200	Indian River	500
Piney Grove	992	487	463	427	139	Piney Grove	1,000
Fentress	992	**1,199**	**1,178**	825	825	Fentress	1,000
No. of Overloads	26	21	19	17	6		

6.3.3 PRELIMINARY TOPOLOGICAL COMPARISON CONCLUSIONS

This high-level study analyzed the performance of different offshore wind delivery systems from the perspective of their impacts on the onshore system during steady-state conditions. The following observations can be made based on the assessment's findings and general knowledge of typical system operations:

- An offshore radial connection will have the least cost to connect a single wind farm to shore. Losing one circuit or one pole in a radial connection with double HVAC circuits or a bipole HVDC system may cause wind generation curtailment during high wind generation conditions.
- A backbone structure increases the reliability of the offshore system above the radial connections. The seven example offshore substations could be connected together to create a backbone structure that demonstrates this increased reliability by allowing full wind generation delivery to shore during the N-1 contingencies studied here. An HVAC backbone system requires reactive compensation equipment for long-distance connections. This will increase the cost of the system because of the need for the compensation equipment as well as the platforms and their associated ancillary equipment and maintenance.
- An HVDC backbone system demonstrates greater flexibility than an HVAC backbone system, because the power flow amounts and direction in an HVDC system can be controlled (within limits) to provide an effective means of reducing much onshore system congestion.
- Grid systems further increase the reliability of an offshore system. The seven example offshore substations could be connected together to create what is essentially a double backbone with connections at each end, which would demonstrate this increased reliability. Again, however, this would require reactive compensation equipment for HVAC grids with long connections between platforms.

- Finally, an HVDC system demonstrated greater flexibility than an HVAC system, because of its ability to control the power flow both on and offshore. The HVDC grid had more capability to do this than the HVDC backbone.

A definitive selection of one system over another cannot be made from this brief evaluation. The final decision will be driven by the overall economics of the system. However, a comprehensive approach is recommended to avoid shortsighted decisions. Capital costs are an important driver, but full operating costs (including maintenance, losses, etc.) and reliability considerations should be taken into account. In addition, careful studies should be made to characterize and quantify the benefits that may result to the entire grid for a given delivery system and design. If future years may result in the ultimate build-out of a grid, early decisions should consider the technologies that will best help that to occur and considerations given to the justification for higher early costs that this might provide. Further, a well-thought approach to transmission development could facilitate access to unused resources. Additional discussions of similar issues are available in the regulatory and policy review in Section 7.0.

6.4 Regional Topology Comparisons

Comparisons of the delivery system topologies were also made on a regional basis to identify local impacts during steady-state conditions. The systems in ERCOT, ISO-NE, MISO, the Carolinas, and PJM were evaluated.

For convenience, Figure 6-22 repeats the 209 wind sites identified during the wind production profile development task (Section 3.0). These sites were used in the 5 regions to help identify the offshore interconnections and the type of delivery system to model.

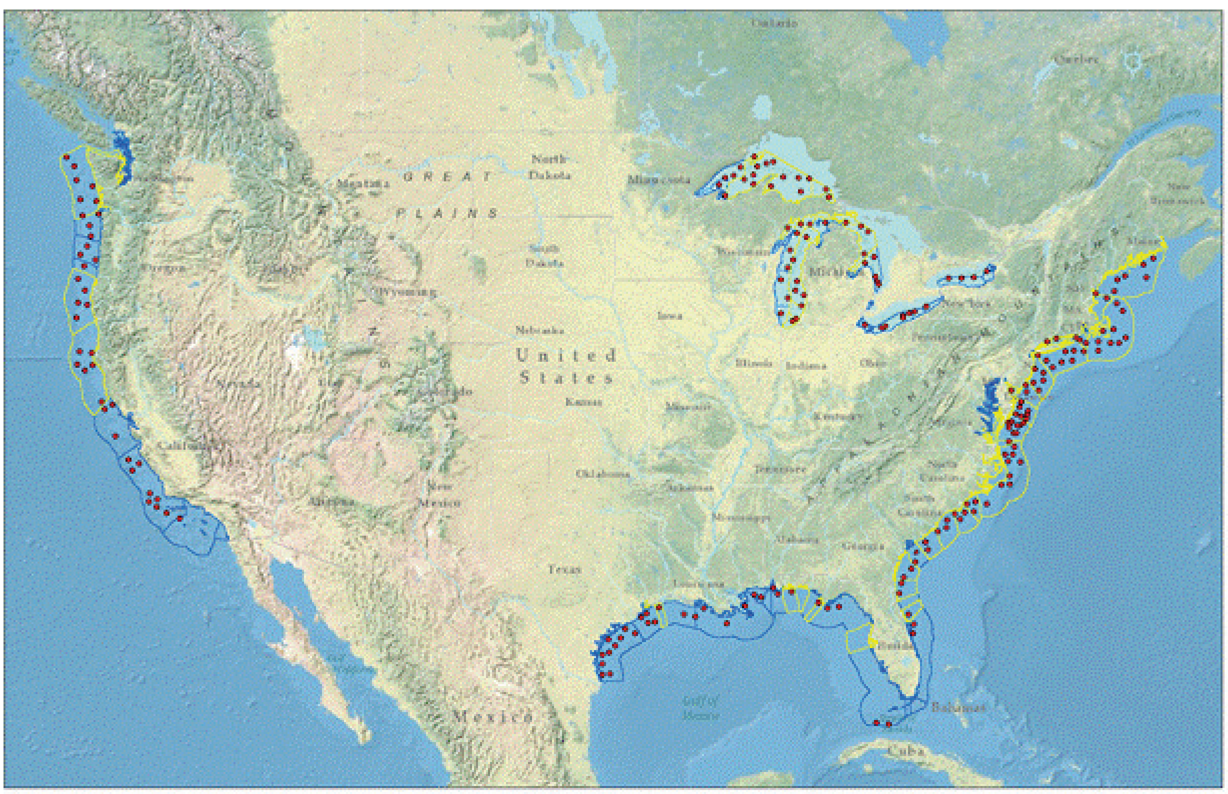


Figure 6-22. Map of wind site locations

As indicated in Section 3.0, 76 wind sites were selected, based on the least COE, to provide the 54 GW targeted for installed offshore capacity. To identify the locations of the onshore interconnections, all substations with voltages of 230 kV and higher were first screened to identify those closest to the selected offshore sites. The list of proposed substations was then submitted to the TRC for review, and the list was modified based on the TRC recommendations

The offshore delivery system type was selected based on the direct distance between a wind site and its nearest substation in the interconnection list. If this direct distance was greater than 50 mi (80 km), then an HVAC delivery system was used. In this case, 230-kV or 345-kV AC cables with 2,000-kcmil cross-sections were assumed. These cables provide 538 MVA or 807 MVA of (nominal) capacity, respectively. Single- or double-circuits were used, depending on the offshore wind site rating. If the charging currents for long AC cables resulted in HV violations at the onshore substations, shunt reactors were added to hold the voltage at acceptable levels.

If the direct distance between an offshore site and its onshore substation was greater than 50 mi, then a HVDC delivery system was used. Depending on the wind site capacity, the HVDC system was assumed to be either single pole or bipole and sized appropriately to provide enough transfer capability to deliver the full production of the offshore site (100% wind site capacity).

After the onshore substations and delivery systems were identified, four study cases were analyzed for each operating area:

1. Base case—no offshore wind
2. Wind generation at 30% of capacity
3. Wind generation at 50% of capacity
4. Wind generation at 100% of capacity

To dispatch the offshore wind, the onshore generation in the base study cases was scaled back to maintain the appropriate generation-to-load balance.

The CF of each selected wind site ranges from 34% to 60%. In some of the system impact studies currently in process by utilities and RTOs or ISOs, system upgrades were proposed to address thermal violations resulting from offshore wind output up to 50% of the installed capacity. In the NOWEGIS effort, a 100% output of installed capacity was considered to capture the worst-case scenario, even though the probability of 100% output is low (see Section 4).

Power flow simulations with the system during nominal and contingency conditions were performed for each of the cases. Results from wind were compared to the base case to identify significant adverse system impacts by the offshore generation. If any element experienced new thermal violations (i.e., overload) not shown in the base case for more than one contingency, only the contingency that resulted in the most limiting condition was reported.

6.4.1 ERCOT

Four of the offshore wind sites, with a total capacity of 2,755 MW, were located off the coast of the Texas Interconnection, as shown in Figure 6-23. The proposed onshore interconnection substations are also shown. Table 6-27 shows the site statistics and the recommended delivery system for these sites.

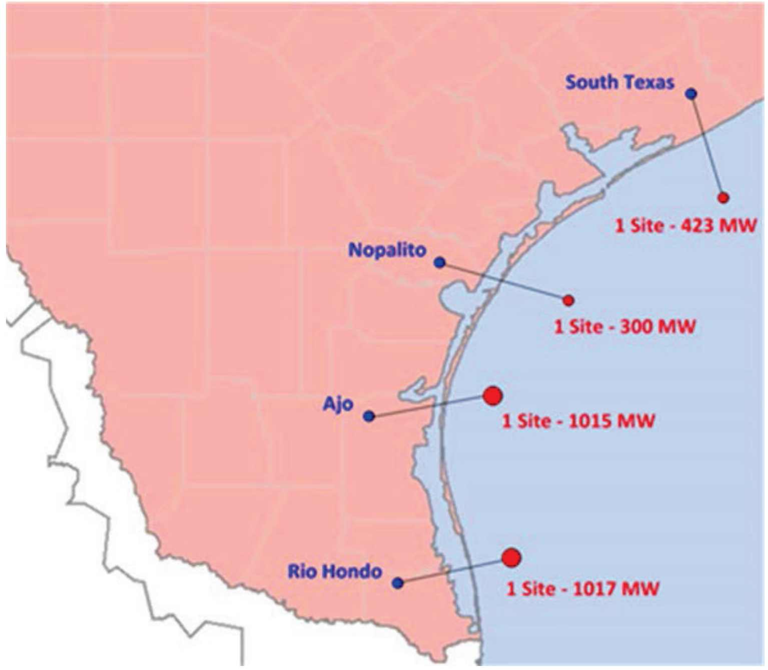


Figure 6-23. Map of wind site locations and onshore interconnections—ERCOT

This evaluation was performed using the ERCOT 2018 Summer Peak Case as the base case. All N-1 contingencies for 100 kV and above according to the ERCOT system and NERC Category B contingencies (as provided by ERCOT) were studied. All 100-kV and above ERCOT network elements were monitored for thermal violations.

Table 6-28 summarizes the new thermal violations with different level of wind output. Detailed results are included in Appendix C.

Table 6-27. Offshore Wind Site Delivery System Recommendation—ERCOT

Onshore Substation	Wind Site	Capacity (MW)	Distance (mi)	Delivery System
Nopalito 345 kV	1012	301	45.7	HVAC
Rio Hondo 345 kV	1031	1,017	32.7	HVAC
Tap on 6 lines out of South Texas 345 kV	1010	423	26.2	HVAC
Ajo 345 kV	1008	1,015	42.6	HVAC
Total		**2,755**		**HVAC - 4** **HVDC - 0**

Table 6-28. Additional Thermal Violations with Offshore Wind—ERCOT

Overloaded Element Type	Voltage Level	Wind Output 30% 827 MW	Wind Output 50% 1,378 MW	Wind Output 100% 2,755 MW
Transmission line	345 kV			1
	138 kV	2	3	12
Transformer	345 kV/138 kV			2

6.4.2 ISO-NE

Of the 76 offshore wind sites, 22 are located in the ISO-NE area, for a total offshore wind capacity of 14,537 MW. Figure 6-24 shows the wind site locations and their onshore interconnection substations.

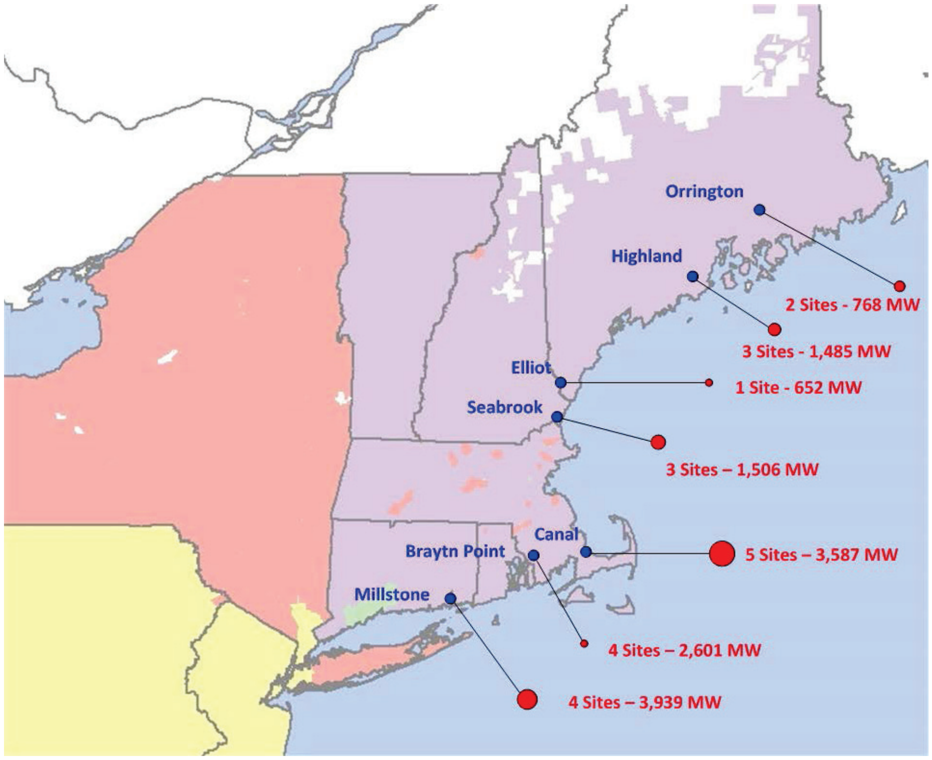


Figure 6-24. Map of wind site locations and onshore interconnections—ISO-NE

Table 6-29 shows the site statistics and the recommended delivery systems for these sites.

The ISO-NE 2030 Summer Peak Case was used as the base case. All contingencies provided by ISO-NE were studied, with all 100-kV and above ISO-NE elements monitored for thermal violations. Table 6-30 summarizes the new thermal violations with different levels of wind output. Detailed results are included in Appendix C.

Table 6-29. Offshore Wind Site Delivery System Recommendations—ISO-NE

Onshore Substation	Wind Site	Capacity (MW)	Distance (mi)	Delivery System	Onshore Substation	Wind Site	Capacity (MW)	Distance (mi)	Delivery System
Brayton Point 345 kV	58	499	49	HVAC	Millstone 345 kV	18	2083	47	HVAC
	56	328	47	HVAC		19	428	63	HVDC
	70	887	78	HVDC		16	1398	72	HVDC
	71	887	58	HVDC		55	30	36	HVAC
Canal 345 kV	21	553	43	HVAC	Orrington 345 kV	146	302	54	HVDC
	10	642	74	HVDC		147	466	64	HVDC
	11	749	78	HVDC	Seabrook 345 kV	9	593	69	HVDC
	20	1,098	61	HVDC		39	562	40	HVAC
	149	545	83	HVDC		73	351	10	HVAC
Elliot 345 kV	145	652	57	HVDC					
Highland 345 kV	144	436	73	HVDC					
	40	891	35	HVAC					
	57	158	46	HVAC					
		Total Capacity	**14,537**		**No. HVAC**	**9**		**No. HVDC**	**13**

Table 6-30. Additional Thermal Violations with Offshore Wind—ISO-NE

Overloaded Element Type	Voltage Level	Wind Output		
		30% 4,361 MW	50% 7,269 MW	100% 14,537 MW
Transmission line	345 kV		2	20
	115 kV	1	3	19
Transformer	345 kV/115 kV	1	3	12

6.4.3 MISO

Of the 76 offshore wind sites, 6 offshore wind sites are located in the MISO area and have a total capacity of 2,413 MW. Figure 6-25 shows the site locations and their onshore interconnection substations, and Table 6-31 shows statistics and the recommended delivery system for these sites.

This evaluation also used the ISO-NE 2030 Summer Peak Case as the base case. All N-1 contingencies for 100 kV and above in the MISO system were studied, with all 100-kV and above MISO system elements monitored for thermal violations. Table 6-32 summarizes the new thermal violations with different levels of wind output. Detailed results are included in Appendix C.

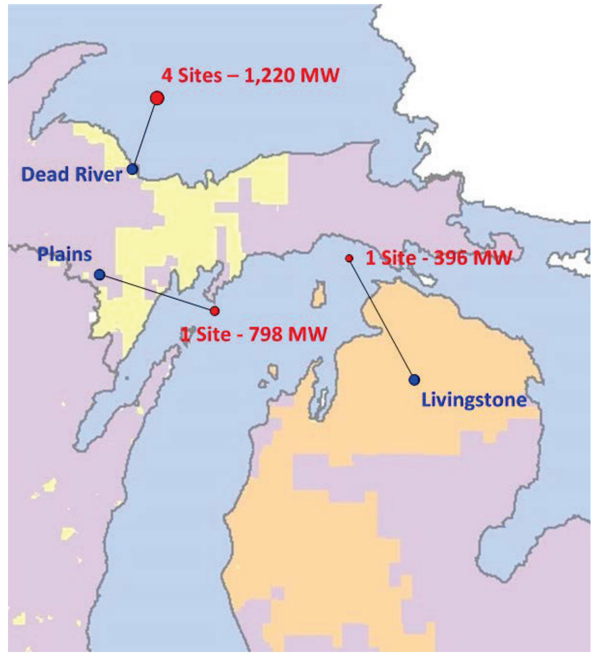


Figure 6-25. Map of wind site locations and onshore interconnections—MISO

Table 6-31. Offshore Wind Site Delivery System Recommendations—MISO

Onshore Substation	Wind Site	Capacity (MW)	Distance (mi)	Delivery System
Livingstone 345 kV	4059	396	53	HVDC
Plains 345 kV	4049	798	46	HVAC
Dead River 345 kV	4010	363	54	HVDC
	4025	367	82	HVDC
	4047	180	47	HVAC
	4024	311	65	HVDC
Total		**2,413**		**HVAC - 2 HVDC - 4**

Table 6-32. Additional Thermal Violations with Offshore Wind—MISO

Overloaded Element Type	Voltage Level	Wind Output		
		30% 724 MW	**50% 1,207 MW**	**100% 2,413 MW**
Transmission line	345 kV	1	2	4
	138 kV	1	4	17
Transformer	345 kV/138 kV		2	2

6.4.4 THE CAROLINAS

Ten of the 76 selected offshore wind sites are located off the coast of the Carolinas. Figure 6-26 shows the wind site locations and their onshore interconnection substations, and Table 6-33 shows the statistics and recommended delivery systems.

This evaluation was performed using the ISO-NE 2030 Summer Peak Case as the base case, and all N-1 contingencies for 100 kV and above in the Duke Energy system were studied. The system 100-kV and above elements in the Duke Energy system were monitored for thermal violations.

Table 6-34 summarizes the new thermal violations for different levels of wind output. Detailed results are included in Appendix C.

DOE funded another offshore wind study that focused on the Carolina coastal region—the *Carolina Offshore Wind Integration Case Study* (COWICS)—which considered a maximum of 5,600 MW of installed offshore wind capacity with interconnection to the Duke Energy system (3,379 MW) and the PJM (2,221 MW) operating area. Figure 6-27 shows the wind site locations and their onshore interconnection substations as considered by COWICS and compares them to the sites selected for NOWEGIS.

In Phase 1 of the COWICS project [19], power flow studies were performed with various levels of wind generation, considering 1,837 MW as the maximum injected into the Duke Energy system (54% wind capacity). As discussed in the COWICS Phase 1 report, some system upgrades were proposed in the Carolina area to alleviate local overloads. These upgrades, listed below, were also applied to NOWEGIS to evaluate the influence of the upgrades in the local area for the 100% penetration case.

- Bucksville Perry Road 230-kV lines—Reinforced by adding a second set of conductors per phase
- Perry Road 230-kV/115-kV transformer bank #3—Replaced 150-MVA bank with 250-MVA bank
- Perry Road Myrtle Beach 115-kV Lines—Upgraded conductor from 556 ACSR to bundled 556 ACSR

Table 6-35 shows the comparison of the original 100% wind output case thermal violations to those of the upgraded case. Detailed results are included in Appendix C.

Even though the wind output level (1,837 MW) in the COWICS project injected into the Duke Energy system is much less than the maximum wind output level (8,281 MW) studied in NOWEGIS, the system upgrades proposed in the COWICS project helped to eliminate some of the thermal violations shown in the original 100% wind output case.

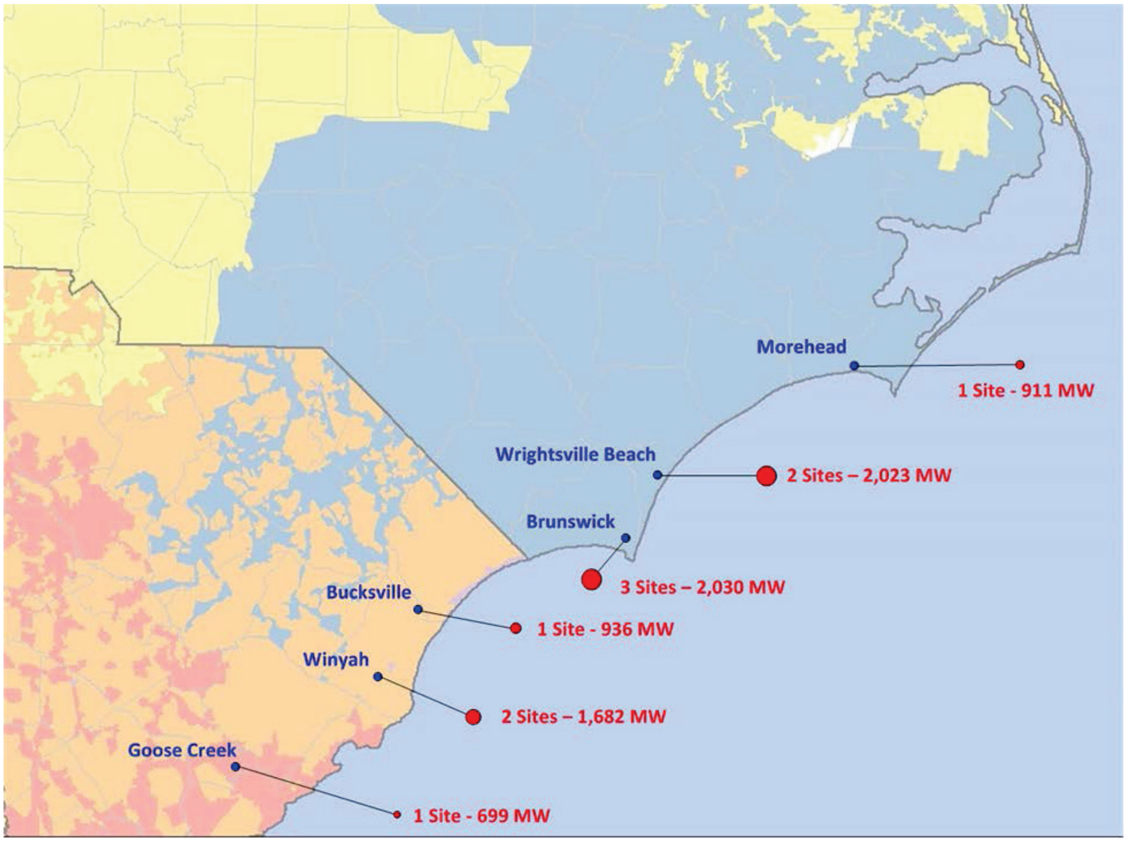


Figure 6-26. Map of wind site locations and onshore interconnections—Carolinas

Table 6-33. Offshore Wind Site Delivery System Recommendations—Carolinas

Onshore Substation	Wind Site	Capacity (MW)	Distance (mi)	Delivery System
Morehead 230 kV	150	911	59	HVDC
Goose Creek 230 kV	1	699	37	HVAC
Winyah 230 kV	13	988	28	HVAC
	14	694	41	HVAC
BUCKSVL 230 kV	12	936	30	HVAC
Brunswick 230 kV	68	408	22	HVAC
	67	1,023	32	HVAC
	148	600	22	HVAC
Wrightsville Beach 230 kV	48	1,014	40	HVAC
	47	1,009	14	HVAC
Total		**8,281**		**HVAC - 9** **HVDC - 1**

Table 6-34. Additional Thermal Violations with Offshore Wind—Carolinas

Overloaded Element Type	Voltage Level	Wind Output		
		30% 2484 MW	50% 4,140 MW	100% 8,281 MW
Transmission line	230 kV	2	7	45
	115 kV			27
Transformer	230 kV/115 kV			5

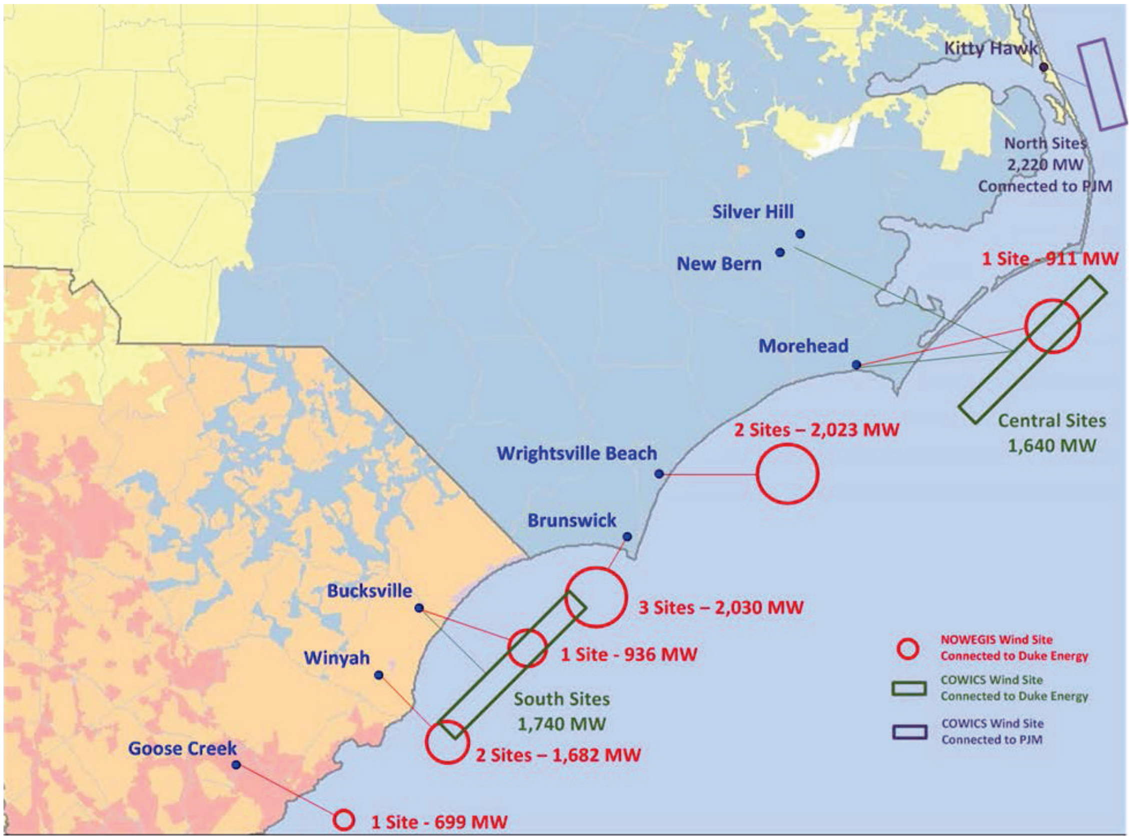


Figure 6-27. Map of wind site locations and onshore interconnections—NOWEGIS compared to COWICS

Table 6-35. Additional Thermal Violation Comparisons for the 100% Case

Overloaded Element Type	Voltage Level	100% Wind Output—8,281 MW	
		Original	Duke Upgrade
Transmission line	230 kV	45	43
	115 kV	27	25
Transformer	230 kv/115 kV	5	6

6.4.5 PJM

A total of 25 of the 76 selected offshore wind sites with a capacity of 20,425 MW were located in the PJM area. Figure 6-28 shows the wind site locations and their onshore interconnection substations. Table 6-36 shows recommended delivery systems for these wind sites.

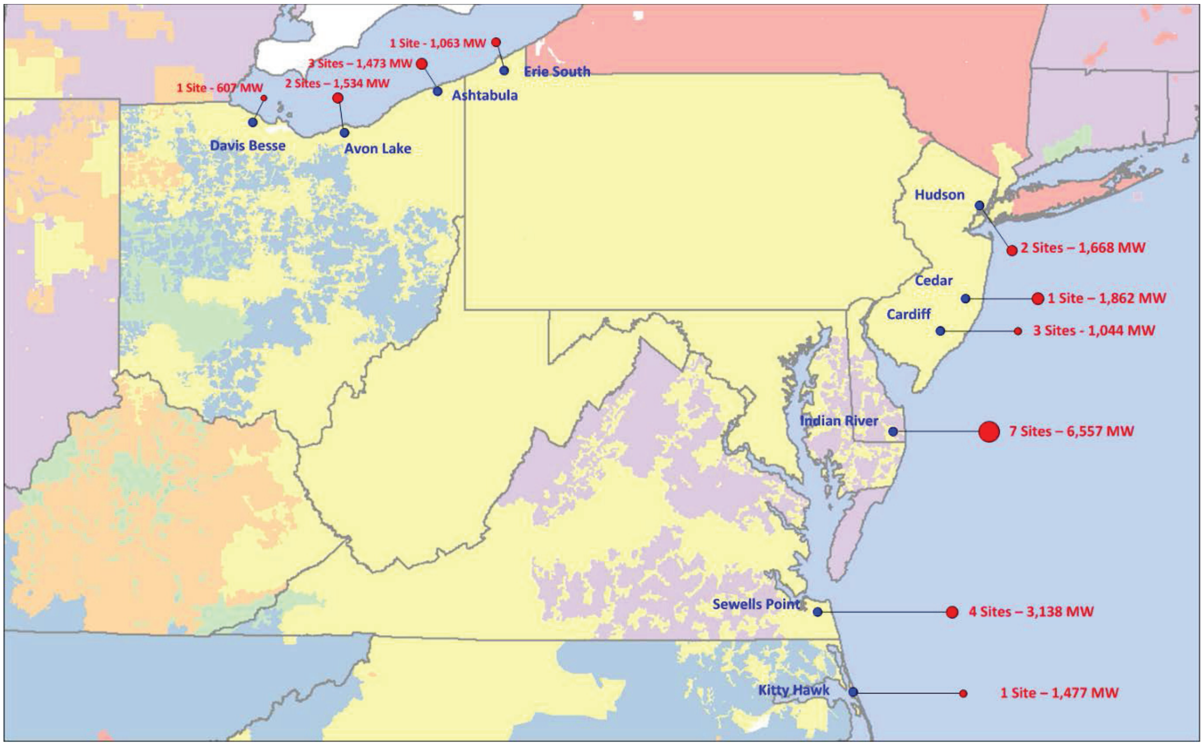


Figure 6-28. Map of wind site locations and onshore interconnections—PJM

Table 6-36. Offshore Wind Site Delivery System Recommendations—PJM

Onshore Substation		Wind Site	Capacity (MW)	Distance (mi)	Delivery System	Onshore Substation		Wind Site	Capacity (MW)	Distance (mi)	Delivery System
North	Hudson 230 kV	52*	817	24	HVAC	South	Sewells Point 230 kV	63	951	54	HVDC
		43*	851	56	HVDC			6*	360	73	HVDC
	Cedar 230 kV	60*	1,862	52	HVDC			64	1,015	59	HVDC
	Cardiff 230 kV	53	25	15	HVAC			66	812	81	HVDC
		38	453	42	HVAC		Kitty Hawk 230 kV	3	1,477	51	HVDC
		69*	567	32	HVAC	Lake	Erie South 345 kV	4043	1,063	21	HVAC
Central	Indian River 230 kV	61	468	30	HVAC		Ashtabula 345 kV	4045	636	13	HVAC
		62	888	31	HVAC			4044	447	16	HVAC
		27	1,352	39	HVAC			4042	391	20	HVAC
		30*	1,015	59	HVDC		Avon Lake 345 kV	4040	595	8	HVAC
		31	977	60	HVDC			4039	940	15	HVAC
		32*	854	68	HVDC		Davis Besse 345 kV	4046	607	9	HVAC
		37*	1,005	77	HVDC						
		Total Capacity	**20,425**				**No. HVAC**	**14**		**No. HVDC**	**11**

* These sites were also considered for an offshore backbone system as discussed below.

The evaluation was performed using the ISO-NE 2030 Summer Peak Case as the base case, and all N-1 outage contingencies for equipment at 100 kV and above in the PJM system were included. Further, all lines and transformers at 100 kV and above were monitored for thermal violations.

Seven of the offshore wind sites with a total capacity of 6,557 MW were connected to the Delaware Peninsula area. For these, the energy flowed north through the local 230-kV and lower transmission system, causing large reactive power losses and a correspondingly low voltages in the local areas. To restore the voltages to reasonable levels (e.g., 0.95 p.u. for system intact conditions), reactive support was added to the study cases. Table 6-37 summarizes the additional reactive support.

Table 6-37. Additional Reactive Support Required in Delaware Peninsula Area (with Different Wind Generation Output Level)

Wind Output	Additional Reactive Supports (MVAr)
30% (6,127 MW)	461
50% (10,212 MW)	2,077
100% (20,425 MW)	11,840

Table 6-38 summarizes the new thermal violations at different levels of wind output. Detailed results are included in Appendix C.

Table 6-38. Thermal Violations with Offshore Wind—PJM

Overloaded Element Type	Voltage Level	Wind Output 30% 6,127 MW	50% 10,212 MW	100% 20,425 MW
Transmission line	500 kV			3
	345 kV			1
	230 kV	24	46	86
Transformer	500/230 kV 500/138 kV	1	1	3
	345/230 kV 345/138 kV	1	1	1
	230/115 kV 230/138 kV	1	5	8

Power flow analyses in the PJM area were also performed assuming offshore backbone systems. (Both HVAC and HVDC systems were considered.) The following seven substations were chosen as the interconnection points of the offshore backbone system (the same as Section 6.3):

- Hudson 230-kV substation
- Sewaren 230-kV substation
- Larrabee 230-kV substation
- Cardiff 230-kV substation
- Indian River 230-kV substation
- Piney Grove 230-kV substation
- Fentress 230-kV substation

The offshore backbone system was assumed to have a 7,000-MW capacity with a 1,000-MW capacity between any two connected substations. Eight wind sites—indicated by an asterisk in Table 6-36—with a total capacity of 7,331 MW were selected to connect to the offshore backbone. Most of the selected wind farms are located far from shore and were recommended to have an HVDC delivery system, which makes them good candidates to connect to the offshore backbone. Figure 6-29 shows offshore wind site interconnections to the offshore backbone system.

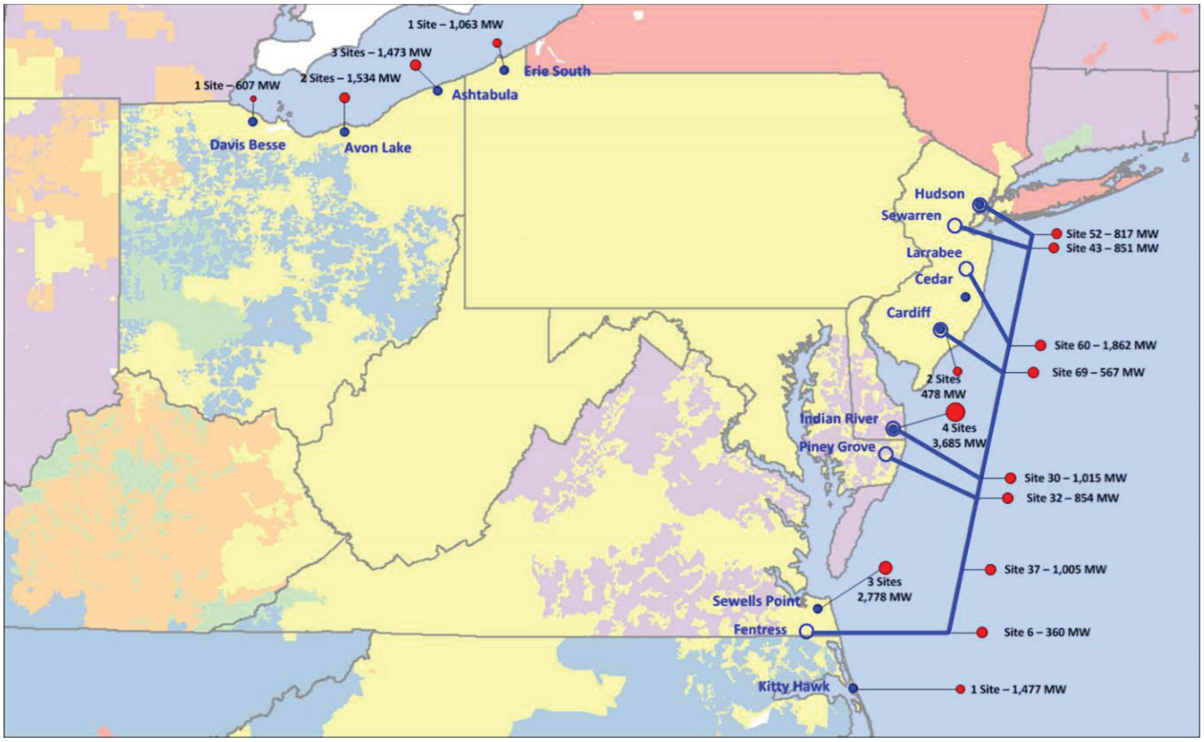


Figure 6-29. Map of offshore wind site interconnections to the offshore backbone system—PJM

The impact of the offshore backbone was evaluated by assuming a 50% output from the offshore wind farms. Based on the sensitivity analysis performed in Section 6.3, the offshore wind generation that was injected into the central region was sent to the north and south through the backbone to mitigate some of the onshore thermal violations. Table 6-39 summarizes the power injection at the onshore substations with various offshore delivery systems. With all of the offshore wind sites connected to shore via radial connections, 3,279 MW of generation were injected to the central Delaware Peninsula area. With an HVDC backbone, the power injected into this area was reduced to 1,848 MW, with the balance shipped north and south to the other substations.

Similar results occurred with the HVAC backbone with no specific control of the power flow (e.g., allowing the power to flow based on the physics of least impedance). As a result, the power generated from the central wind sites tended to flow to the north and south.

By adding the offshore backbone system to ship much of the central offshore wind generation to the north and south, voltage issues in the Delaware Peninsula improved considerably compared to those when using radial connections.

Table 6-40 summarizes the additional reactive support required in the area for different offshore delivery systems; whereas Table 6-41 summarizes the new thermal violations at 50% output. Detailed results are included in Appendix C. As shown, an offshore backbone helps to alleviate several of the onshore thermal violations.

Table 6-39. Onshore Substation Power Injection with Different Offshore Delivery Systems

Onshore Substation	Onshore Substation	HVAC Radial	HVDC Backbone		HVAC Backbone	
		Total (MW)	BB (MW)	Total (MW)	BB (MW)	Total (MW)
North	Hudson 230 kV	834	894	894	771	771
	Sewaren 230 kV		985	985	469	469
	Larrabee 230 kV		400	400	741	741
	Cedar 230 kV	931		0		0
	Cardiff 230 kV	522	375	614	719	958
	Total	**2,287**		**2,892**		**2,939**
Central	Indian River 230 kV	3,279	0	1,842	-42	1,800
	Piney Grove 230 kV		6	6	215	215
	Total	**3,279**		**1,848**		**2,015**
South	Fentress 230 kV		985	985	741	741
	Sewells Point 230 kV	1,569		1,389		1,389
	Kitty Hawk 230 kV	738		738		738
	Total	**2,307**		**3,112**		**2,868**

Table 6-40. Additional Reactive Supports Required in Delaware Peninsula Area (Various Offshore Delivery Systems with 50% Wind Generation Output Levels)

Wind Output	Additional Reactive Supports (Mvar)
Radial	2,077
HVDC backbone	324
HVAC backbone	391

Table 6-41. Thermal Violations with Different Offshore Wind Delivery Systems—PJM

Overloaded Element Type	Voltage Level	50% Wind Output—10,212 MW		
		Radial	HVDC BB	HVAC BB
Transmission line	500 kV			
	345 kV			
	230 kV	46	29	32
Transformer	500 kV/230 kV 500 kV/138 kV	1		
	345 kV/230 kV 345 kV/138 kV	1	1	1
	230 kV/115 kV 230 kV/138 kV	5	3	3

6.4.6 CONCLUSIONS

The steady-state evaluations performed in Sections 6.3 and 6.4 represent a preliminary look at stability issues. More detailed and specific studies must be conducted for any offshore wind development whether the onshore connections are made through radial, backbone, or offshore grid systems. Nevertheless, some useful and general principles appear to have emerged from this theoretical study.

- If the load centers are close to shore, the interconnection of offshore wind generation does not appear to cause significant adverse system impacts.
- If large amounts of offshore generation must flow for long distances through lower voltage transmission systems (e.g., 230-kV and below) to reach a load center, severe voltage problems and significant system overloads along the path may result.

- An alternative offshore path (e.g., offshore backbone or offshore grid system) can help to alleviate many of the voltage issues and mitigate onshore congestion, making it a possible alternative to onshore transmission reinforcements.
- Offshore HVDC backbone and grid systems show the potential for increased general control of the flow of offshore wind power.

6.5 Production Cost Impact Assessment

Offshore wind farms close to major load centers have the unique advantage of delivering clean and low-cost energy close to loads. In the United States, existing transmission congestion issues have limited the economic power delivery to the load centers along the eastern seaboard, resulting in high energy prices in those load centers. Because of this, power supply from offshore wind and economic energy transfer via offshore delivery systems can be an attractive option.

The purpose of the production cost impact assessments was to help evaluate the value of integrating bulk offshore wind power in the United States.

ABB's GridView software was chosen as the production cost simulation tool. GridView is a software application recognized by the industry for studying the market operation of an electric power system with transmission security constraints [20].

An operational model of the North American electric power system (U.S. and Canada) was developed in GridView representing the expected supply, demand, and transmission grid of 2020. Included in the model were seventy-six offshore wind farms were selected from the Atlantic, Gulf of Mexico, Great Lakes, and Pacific regions, with a total capacity of 54 GW.

Production cost simulations were performed with appropriate assumptions to evaluate the value of offshore wind power. By comparing the simulation results with and without offshore wind power, the regional impacts have been estimated in terms of generation outputs and production costs.

Finally, sensitivity analyses were performed on the economic value of offshore wind power for different gas prices and offshore wind penetration levels.

6.5.1 PRODUCTION COST MODEL AND ASSUMPTIONS

To properly assess the economic benefits of offshore wind power, an operational model of the North American electric power system was adopted. For this purpose, GridView was chosen as the production cost simulation tool. Typical applications of GridView include the:

- Determination of generator and transmission line utilization
- Calculation of generation production costs
- Calculation of location marginal prices (LMP)
- Identification of transmission bottlenecks and system congestion
- Evaluation of the economic value of transmission expansion projects
- Evaluation of the operational and economic impacts of renewable energy resources

GridView simulates the economic operation of a power system in hourly intervals for periods ranging from one day to multiple years. It incorporates detailed models of the supply, demand, and transmission system. By performing transmission and security-constrained optimization of the system resources against spatially distributed loads, GridView produces a realistic forecast of the electric energy prices, utilization levels of power system components, and power flow patterns in the regional or continental transmission grid.

North America Transmission Grid Modeling

An operational model of the North American electric power system was developed to represent the expected supply, demand, and transmission grid scenario of 2020. The model integrates the Eastern Interconnection, Western Interconnection, and Texas Interconnection into one database. The geographical scope of the North America transmission grid is shown in Figure 6-30.

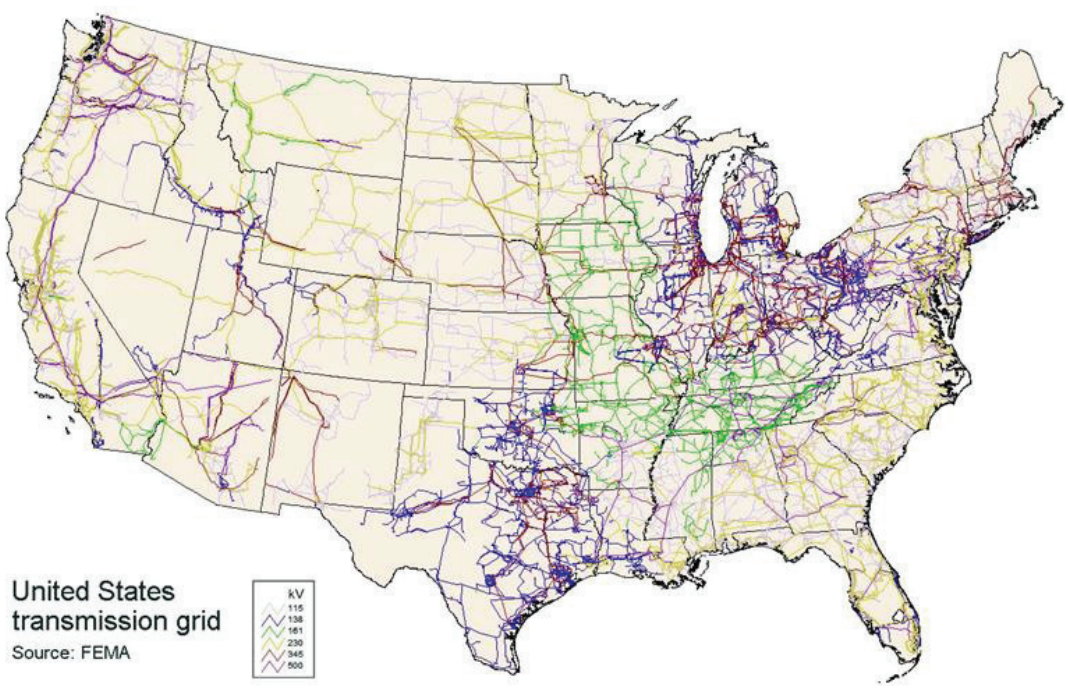


Figure 6-30. Transmission grids of North America
(Illustration from http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)

Table 6-42 shows the details of the three interconnections and the integrated North America Transmission Grid Model (NAMTGM-2020). The detailed supply model consisted of thermal generators, hydro plants, pumped storage plants, and renewable resources such as wind and solar plants that currently exist or are expected by 2020. Expected retirements by the year 2020 were not dispatched. For thermal generators, detailed parameters (such as heat rates, minimum up and down times, and start-up cost) were needed for unit commitment and economic dispatch. The demand model consisted of 190 load profiles, one for each load area. These load profiles were generated from the reported 2006 control area hourly demands and adjusted based on the NERC regional peak and energy projections for 2020. The model was not developed out to 2030 because of the unavailability of data on generation and transmission.

Table 6-42. Details of the Integrated NAMTGM

Element	Eastern	Western	Texas	NAMTGM
Bus	64,318	17,529	6,265	8,8112
Generator	6,097	3,143	399	9,639
Branch	82,742	22,587	7,783	113,112
Interface	279	156	N/A	435
Load area	147	39	4	190

Offshore Wind Farm and Delivery System Modeling

As described in Sections 2.0 and 0, 76 offshore wind sites with a total capacity of 54 GW, were selected based on the COE. The site data used is summarized in Appendix D. Figure 6-31 shows the aggregated wind generation duration curves of the four offshore regions.

The aggregated CFs for the offshore wind in the Pacific, Gulf, Great Lakes, and Atlantic regions are 55.8%, 42.1%, 33.6%, and 43.1%, respectively. Overall, the 54 GW of offshore wind has an available CF of 43.2% and could produce 205 TWh of energy annually.

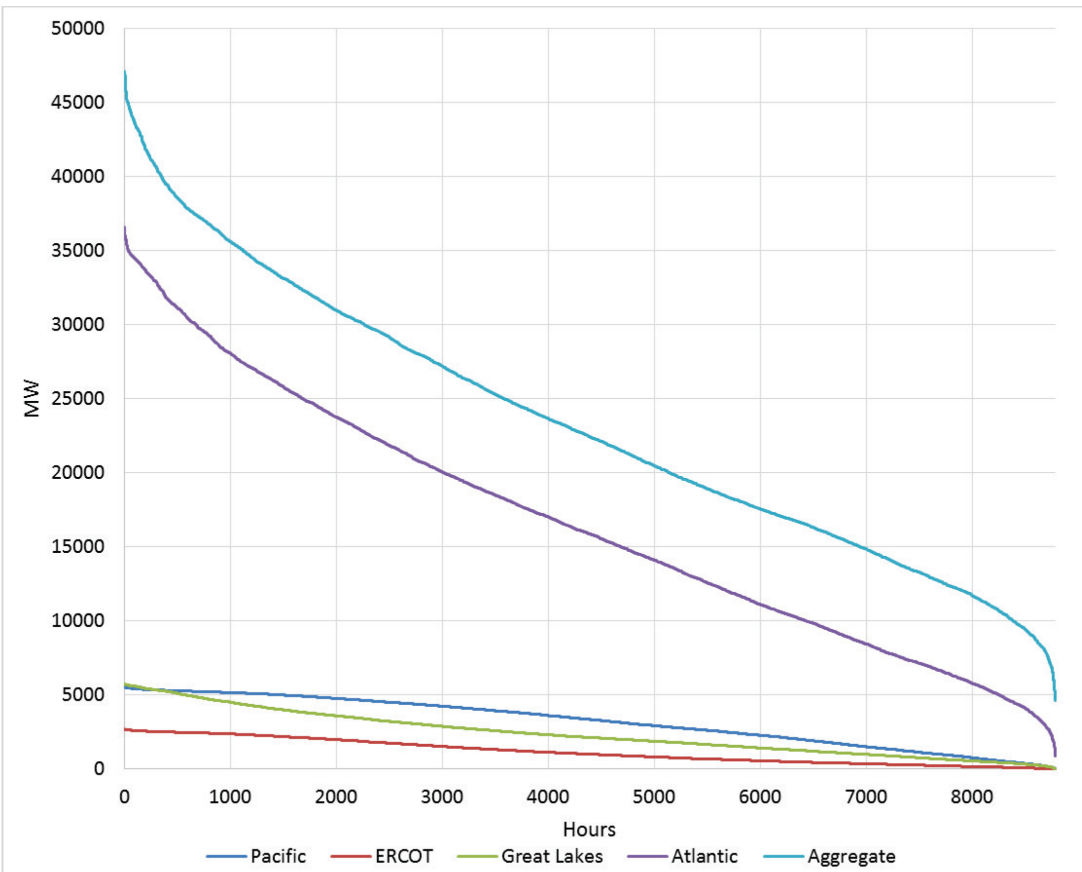


Figure 6-31. Wind generation duration curves by offshore regions

Each offshore wind farm is connected to a designated onshore substation by a radial delivery system. For high-capacity offshore wind farms, a radial delivery system may consist of two or three parallel circuits. Local transmission upgrades were considered so that the total capacity of outgoing circuits and transformers at the interconnection substation was higher than the offshore wind farm nameplate capacity. A detailed study of the necessary transmission upgrades was beyond the scope of this effort. (See Section 6.4 for more information.)

For the simulations, it was assumed that no operational cost is associated with offshore wind generation; therefore, offshore wind generation resources have priority over thermal generators in the economic dispatch. The simulation model also allows wind energy to be curtailed if the total wind power cannot be delivered because of commitment or onshore transmission grid constraints. The impacts of generation and transmission outages were not considered in this study.

<u>Fuel Prices for Power Generation</u>

The addition of low-cost renewable energy typically replaces generation from natural gas and coal-powered units. Although the production cost of nuclear units may be similar to that of coal-fired units, these units were always dispatched as must-run base-load units. Other types of generating units, such as oil and biomass, were only a small percentage of the total generation mix. In other words, the main economic benefits of offshore wind power are the production cost savings obtained by replacing generation from natural gas and coal power plants; therefore, the results are highly dependent on the prices assumed for those fuel types.

The fuel prices were obtained from EIA's *Annual Energy Outlook 2013* [21]. Figure 6-32 shows the map of EIA electric market module regions, and Table 6-43 gives the projected natural gas and coal prices for 2020 in both $2011 and nominal $2020. All calculations were made using nominal dollars.

Note that the coal prices shown in the EIA report were significantly higher for New York City and Long Island, likely because of incurred emission cost adders. However, it is expected that these high-cost coal-fired plants will not be dispatched, because the production cost simulation assumptions do not define nor enforce in-city reliability must-run requirements.

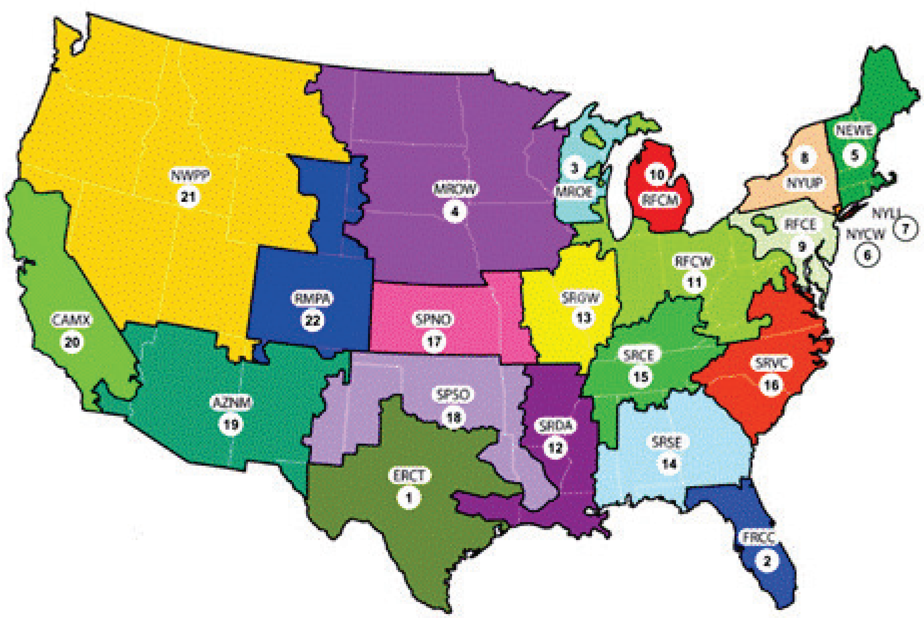


Figure 6-32. EIA Electricity Market Module (EMM) regions

Table 6-43. Fuel Prices by EMM Region in $2020, $2011, and $Nominal

EIA EMM Region		Coal Prices		Natural Gas Prices	
		$2011	$Nominal	$2011	$Nominal
WECC Northwest	NWPP	1.88	2.17	4.96	5.72
WECC Rockies	SWPA	1.91	2.2	5.25	6.05
WECC California	CAMX	2.04	2.35	5.14	5.92
WECC Southwest	AZNM	2.37	2.73	5.27	6.07
MRO West	MOROW	1.9	2.19	4.98	5.74
MRO East	MORE	2.44	2.81	4.67	5.39
NPCC Upstate New York	NYUP	3.05	3.52	5.01	5.77
NPCC New York City/Westchester	NYCW	17.5	20.18	5.01	5.77
NPCC Long Island	NYLI	17.5	20.18	5.01	5.77
NPCC New England	NEWE	3.59	4.14	5.12	5.91
RFC West	RFCW	2.69	3.11	4.88	5.63
RFC Michigan	RFCM	2.4	2.77	4.67	5.39
RFC East	RFCE	2.97	3.42	5.02	5.79
SERC Central	SRCE	2.58	2.98	4.69	5.4
SERC Gateway	SRGW	2.24	2.58	4.69	5.41
SERC VA CAR	SRVC	3.67	4.24	5.23	6.03
SERC Delta	SRDA	2.19	2.53	4.35	5.02
SERC Southeastern	SRSE	3.05	3.52	4.89	5.64
SPP North	SPNO	1.92	2.21	5.19	5.99
SPP South	SPSO	2.15	2.47	4.32	4.99
FRCC	FRCC	3.22	3.72	5.79	6.67

Regional Reserve Requirements

Regional operating reserve requirements are important parameters for production cost simulation studies. For this assessment, the regional operating reserve requirements were determined with consideration of both contingency and regulating reserve requirements.

The contingency reserve requirements in the Eastern Interconnection are commonly determined as the outage backup for the largest generating unit or power plant. This approach also applies to the Texas Interconnection. The contingency reserves in the Western Interconnection are required as a percentage of the hourly demands. Table 6-44 shows the generation contingency reserve requirements considered in this study for different regions.

Regional regulating reserve requirements were also calculated based on the net hourly load profiles and taking into account the fluctuating wind power generation, as discussed in Section 4.0.

Table 6-44. Regional Contingency Reserve Requirements

GridView Region	NERC Region	NERC Subregion	Interconnection	Contingency Reserve MW	Contingency Reserve %
CANADA	WECC	WECC-BC	Western		4
NWPP	WECC	NWPP	Western		4
RMPP	WECC	RMPA	Western		4
BASIN	WECC	BASIN	Western		4
CALIF_NORTH	WECC	CALN	Western		4
CALIF_SOUTH	WECC	CALS	Western		4
AZNMNV	WECC	WECC-DSW	Western		4
ERCOT	ERCOT	ERCOT	Texas	1,150	
Saskatchewan	MRO	MRO-Canada	Eastern	111	
MISO - Manitoba	MRO	MRO-Canada	Eastern	78.5	
Dakotas	MRO	MRO-U.S.	Eastern	150	
MISO	MRO	MRO-U.S.	Eastern	2,003	
IESO (Ontario)	NPCC	Ontario	Eastern	1,379	
Quebec	NPCC	Quebec	Eastern	1,000	
Maritimes	NPCC	Maritimes	Eastern	635	
New York	NPCC	New York	Eastern	1,200	
ISO-NE	NPCC	ISO-NE	Eastern	1,249	
PJM Interconnection	RFC	RFC	Eastern	2,789	
Kentucky	SERC	SERC-N	Eastern		3
TVA	SERC	SERC-N	Eastern	1,264	
Carolinas	SERC	SERC-E	Eastern	1,033	
Delta	SERC	SERC-W	Eastern	676	
Southeastern	SERC	SERC-SE	Eastern		4
SPP - Central	SPP	SPP	Eastern	635	
SPP - KSMO	SPP	SPP	Eastern	393	
SPP - Louisiana	SPP	SPP	Eastern	67	
SPP - Nebraska	SPP	SPP	Eastern	125	
Florida	FRCC	FRCC	Eastern	930	

6.5.2 BASE RESULTS

A one-year transmission-constrained simulation was first performed for the NAMTGM-2020 without offshore wind power to establish a baseline for comparison. In the simulation setup, the capacity limits of 345-kV and above transmission lines, transmission interfaces, and HVDC links were monitored. Capacity limitations of individual transmission lines below 345 kV were not monitored, and generation outage events and transmission contingencies were not considered.

A one-year simulation was then performed for the NAMTGM-2020 with the 54 GW of offshore wind. The 76 offshore wind farms were connected to respective interconnection substations by radial delivery systems. Similar to the simulation setup in the base case, all 345-kV and above transmission lines, transmission interfaces, and HVDC links were monitored. As before, capacity limitations of transmission lines below 345 kV, generator outage events, and transmission contingencies were not considered.

Table 6-45 shows the dispatch summary of offshore wind power for each of the coastal areas considered in this study. These results show that the offshore wind power was not fully dispatched because of onshore transmission constraints. The estimated production loss or curtailment of wind energy is approximately 17.5 TWh, or 8.5% of the available wind generation. Note that the curtailment of wind energy could increase during security-constrained dispatch (N-1 transmission contingencies). As determined in the technology topological assessments of Section 6.3, considerable upgrades may be needed for the coastal region transmission network to meet N-1 transmission contingency criteria.

Table 6-45. Offshore Wind Power Dispatch Summary by Coastal Region

Production Quantity	Pacific	Gulf	Great Lakes	Atlantic	Total
Offshore wind capacity (MW)	5,715	2,755	7,091	38,564	54,125
CF (%)	55.78	32.06	26.58	39.95	39.47
Offshore wind generation (TWh)	28.0	7.8	16.6	135.3	187.6
Offshore wind curtailment (TWh)	0	2.4	4.4	10.7	17.5
Offshore wind curtailment (%)	0	23.8	20.8	7.3	8.5

Table 6-46 presents a summary of the base case simulation results by interconnection and NERC subregion. With 54 GW of offshore wind power, the total annual production costs were reduced by $7.68 billion.

Table 6-46. Summary of Base Production Costs by NERC Subregion

Inter-connection	NERC Region	NERC Subregion	Load (TWh)	Total Generation (TWh)			Production Cost (M$)	
				No Wind	With Wind	(Offshore)	No Wind	54 GW Wind
Western	WECC	WECC-BC	162.3	158.9	158.0		2,288	2,247
Western	WECC	NWPP	183.6	232.2	239.7	(14.2)	2,308	2,009
Western	WECC	RMPA	79.1	75.7	75.4		1,636	1,622
Western	WECC	BASIN	88.5	108.8	106.9		2,140	2,068
Western	WECC	CALN + CALS	331.6	279.9	281.8	(13.8)	7,464	6,897
Western	WECC	WECC-DSW	155.3	178.3	174.7		4,957	4,778
		Interconnection Total	*1,000.5*	*1,033.8*	*1,036.5*	*(28.0)*	*20,793*	*19,621*
Texas	ERCOT	ERCOT	381.0	389.9	390.7	(7.8)	10,132	9,892
Eastern	MRO	MRO-Canada	51.6	52.2	51.9		355	346
Eastern	MRO	MRO-U.S.	509.4	603.4	602.4	(16.6)	15,138	14,885
Eastern	NPCC	Ontario	157.8	166.5	162.8		1,878	1,714
Eastern	NPCC	Quebec	207.4	216.8	215.9		148	109
Eastern	NPCC	Maritimes	27.7	19.8	18.0		489	379
Eastern	NPCC	New York	165.9	162.3	149.5		4,441	3,855
Eastern	NPCC	ISO-NE	146.8	151.0	165.0	(53.8)	4,733	2,975
Eastern	RFC	RFC	934.3	902.1	919.3	(55.2)	23,709	21,689
Eastern	SERC	SERC-N	227.0	247.8	246.2		6,061	6,006
Eastern	SERC	SERC-E	232.5	237.4	239.4	(26.3)	6,473	5,504
Eastern	SERC	SERC-W	168.1	167.2	166.1		4,505	4,463
Eastern	SERC	SERC-SE	278.2	294.9	288.8		9,029	8,786
Eastern	SPP	SPP	254.6	266.7	266.5		6,528	6,513
Eastern	FRCC	FRCC	254.6	227.9	227.8		9,900	9,896
		Interconnection Total	*3,615.8*	*3,716.0*	*3,719.5*	*(151.9)*	*93,387*	*87,120*
		National Total:	***4,997.2***	***5,139.6***	***5,146.7***	***(187.6)***	***124.3***	***116.6***

Although not all of the regions operate with an energy market structure, LMP calculated assuming generation dispatched on an economic basis provides some insight into the impact of the offshore wind. Figure 6-33 and Figure 6-34 show LMP contour maps with no offshore wind and with the 54 GW of offshore wind. The differences between the maps indicate large disparities in LMP across the North

America transmission grids. Offshore wind tends to lower the LMP along the coastal regions and, to a lesser extent, in those next to these regions.

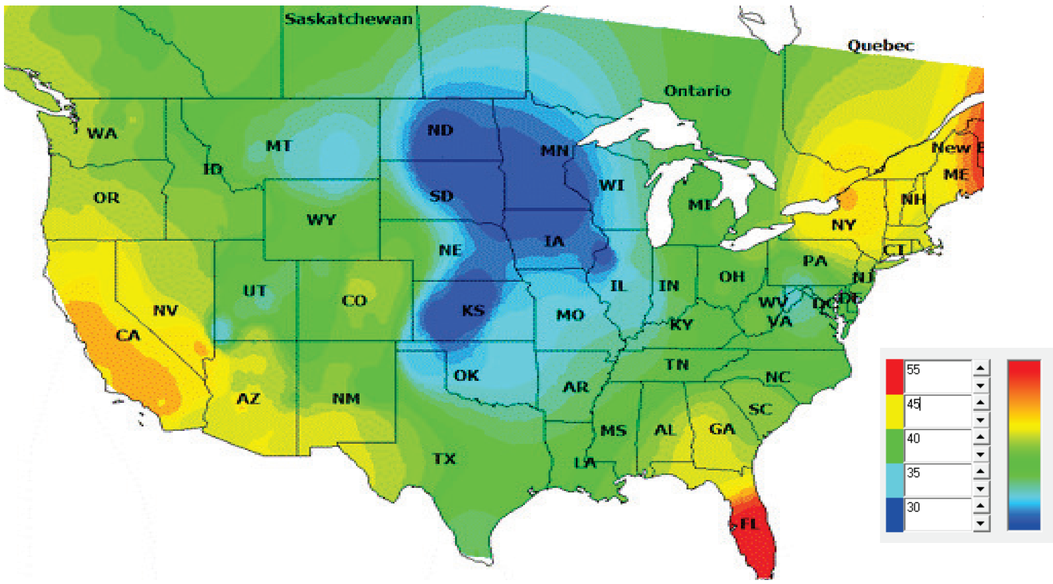


Figure 6-33. LMP contour map without offshore wind power

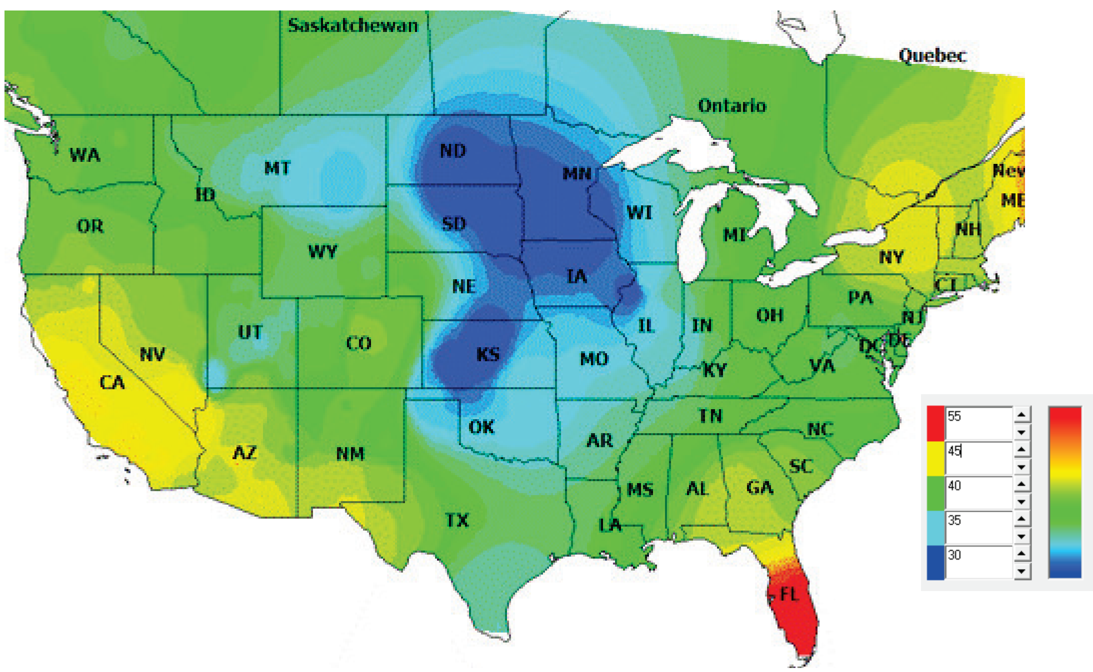


Figure 6-34. LMP contour map with 54 GW offshore wind power

Based on these results above, the following are noted:

- Large production cost reductions were observed in the coastal regions that have high penetrations of offshore wind power, including the Carolinas, ISO-NE, PJM, NWPP, and California. The estimated production cost savings in these regions result from the replacement of high-cost thermal generation by the offshore wind generation.

- Increased total generation output was observed in the coastal regions with high penetrations of offshore wind, indicating a reduction in energy imports from neighboring regions.
- Both reduced generation output and reduced production costs were observed for regions without offshore wind power, too, particularly for those regions next to coastal regions with offshore wind (e.g., New York, Southeastern, and IESO). These regions experienced lower energy exporting to the coastal regions, resulting in lower production costs.
- Increased generation was observed in Texas, which was assumed to have no energy exchange with the Eastern and Western interconnections. Because the load did not change from the base case, this result would indicate increased transmission losses for transporting the offshore wind power to the load centers.
- Reduced generation was observed in the MISO region, indicating that the total wind generation from the Great Lakes is less than the reduction in exported energy.

The economic value of offshore wind power can be estimated based on the production cost simulation results shown in Table 6-46. Dividing the total production cost savings ($7.68 billion) of the entire North American grid by the total offshore wind generation (187.6 TWh), the estimated value of the offshore wind from the perspective of production cost reduction is approximately $41.0/MWh. Similarly, calculating the values for the individual interconnections gives offshore wind value estimates of $42.9/MWh for the Western Interconnection, $31.0/MWh for the Texas Interconnection, and $41.3/MWh for the Eastern Interconnection.

In addition, the values for offshore wind power should be adjusted to include the cost of emissions. The average CO_2 emission rates in the United States are 1,135 lbs/MWh from natural gas-fired generation and 2,249 lbs/MWh from coal-fired generation. The simulation results showed that offshore wind displaced approximately 130.8 TWh of gas-fired generation and 48.5 TWh of coal fired generation. Using an assumed CO_2 cost of $20 per metric ton, the national average of offshore wind increases by $12.5/MWh, or $2.34 billion annually. This brings the total value of 54 GW of offshore wind power to $10.02 billion, or $53.5/MWh.

6.5.3 High Gas Price Sensitivity

The current EIA *Annual Energy Outlook* assumes a significant increase in production from shale gas resources and, therefore, relatively low natural gas prices. At the request of the TRC, additional simulations were performed for a more conservative gas price, with a 20% increase in gas prices above the EIA projections. Table 6-47 presents the results with the higher gas prices and without the 54 GW of offshore wind.

These results show that with gas prices 20% higher than the original assumption, the production cost savings would be $8.89 billion, an increase of 15.7%. The value of the offshore wind would be approximately $47.4 MWh. The value for each interconnection is then approximately $48.5/MWh in the Western Interconnection, $35.3/MWh in the Texas Interconnection, and $47.7/MWh in the Eastern Interconnection.

The impact on LMPs with the higher gas prices is shown in Figure 6-35 and Figure 6-36.

Table 6-47. Summary of Production Costs with High Gas Prices

Inter-connection	NERC Region	NERC Subregion	Load (TWh)	Total Generation (TWh)			Production Cost (M$)	
				No Wind	With Wind	(Offshore)	No Wind	54 GW Wind
Western	WECC	WECC-BC	162.3	158.7	157.8		2,459	2,412
Western	WECC	NWPP	183.6	232.2	239.7	(14.2)	2,502	2,153
Western	WECC	RMPA	79.1	75.8	75.5		1,684	1,673
Western	WECC	BASIN	88.5	109.1	107.3		2,216	2,136
Western	WECC	CALN + CALS	331.6	279.1	281.3	(13.8)	8,450	7,799
Western	WECC	WECC-DSW	155.3	179.0	175.1		5,297	5,076
		Interconnection Total	*1,000.5*	*1,034.0*	*1,036.6*	*(28.0)*	*22,608*	*21,249*
Texas	ERCOT	ERCOT	381.0	389.9	390.7	(7.8)	11,092	10,817
Eastern	MRO	MRO-Canada	51.6	52.1	51.8		358	349
Eastern	MRO	MRO-U.S.	509.4	609.3	607.2	(16.6)	15,507	15,219
Eastern	NPCC	Ontario	157.8	166.0	162.4		1,978	1,786
Eastern	NPCC	Quebec	207.4	216.7	215.9		163	117
Eastern	NPCC	Maritimes	27.7	19.6	17.8		535	407
Eastern	NPCC	New York	165.9	161.1	146.9		5,055	4,279
Eastern	NPCC	ISO-NE	146.8	151.2	165.3	(53.8)	5,461	3,414
Eastern	RFC	RFC	934.3	899.8	919.2	(55.2)	24,875	22,515
Eastern	SERC	SERC-N	227.0	249.6	247.1		6,247	6,155
Eastern	SERC	SERC-E	232.5	249.6	254.3	(26.3)	7,235	6,339
Eastern	SERC	SERC-W	168.1	162.7	161.1		4,731	4,654
Eastern	SERC	SERC-SE	278.2	285.9	279.5		9,125	8,812
Eastern	SPP	SPP	254.6	266.8	266.3		6,751	6,724
Eastern	FRCC	FRCC	254.6	228.0	228.0		11,583	11,581
		Interconnection Total	*3,615.8*	*3,718.7*	*3,722.8*	*(151.9)*	*99,604*	*92,351*
		National Total:	***4,997.2***	***5,142.5***	***6,186.8***	***(187.6)***	***133,306***	***124,417***

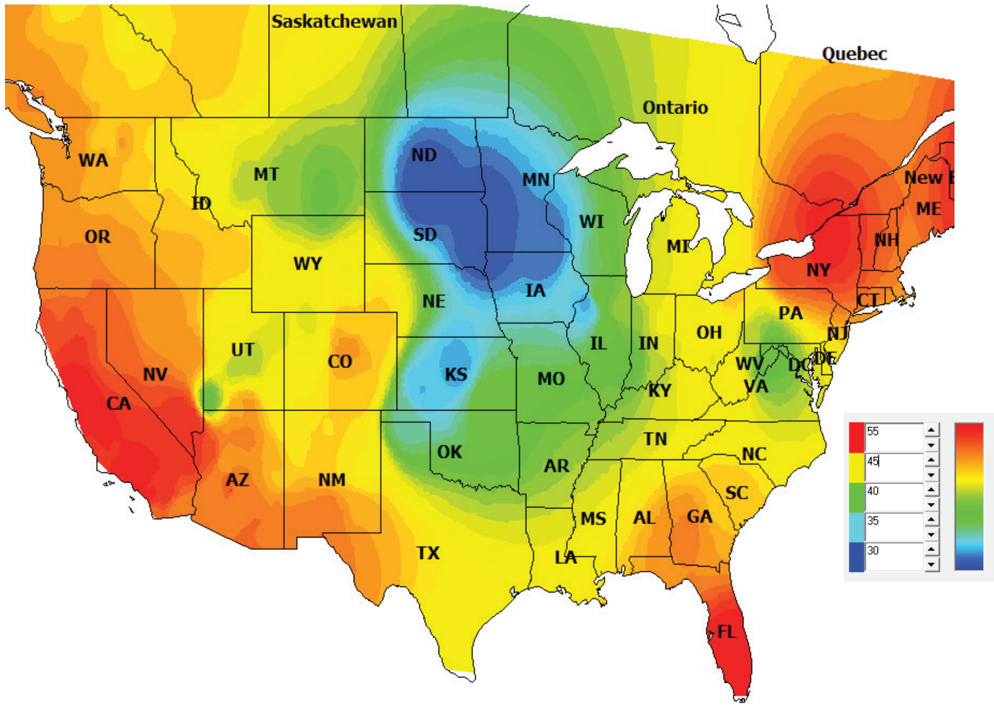


Figure 6-35. LMP contour map without offshore wind power (20% higher gas prices)

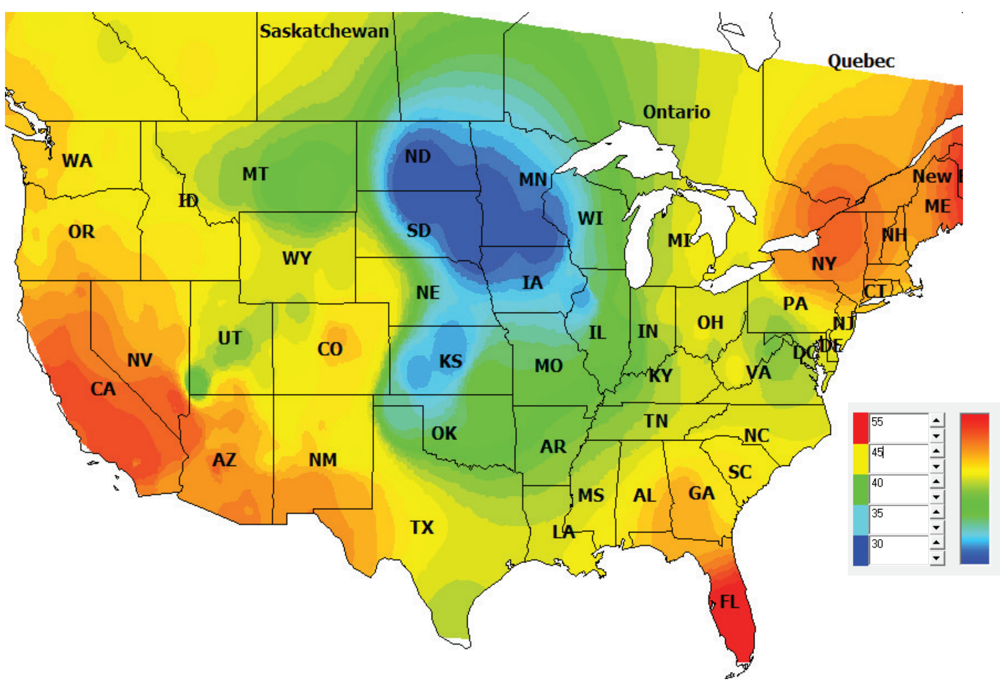


Figure 6-36. LMP contour map with 54 GW of offshore wind power (20% higher gas prices)

6.5.4 LOW GAS PRICE SENSITIVITY

Additional simulations were performed assuming a 10% reduction in natural gas prices. Table 6-48 compares the production cost results of the base case to the case with 54 GW and low gas prices (10% lower than the base assumption).

With low gas prices, the production cost savings decreased by 6.5%, to $7.18 billion. The estimated value of the offshore wind would be approximately $38.3/MWh nationally, $38.4/MWh in the Western Interconnection, $31.7/MWh in the Texas Interconnection and $38.6/MWh in the Eastern Interconnection.

Table 6-48. Summary of Production Costs with Low Gas Prices

Inter-connection	NERC Region	NERC Subregion	Load (TWh)	Total Generation (TWh)			Production Cost (M$)	
				No Wind	With Wind	(Offshore)	No Wind	54 GW Wind
Western	WECC	WECC-BC	162.3	159.0	158.1		2,203	2,163
Western	WECC	NWPP	183.6	232.2	239.6	(14.2)	2,210	1,931
Western	WECC	RMPA	79.1	75.5	75.3		1,607	1,596
Western	WECC	BASIN	88.5	108.6	106.8		2,098	2,034
Western	WECC	CALN + CALS	331.6	280.4	282.4	(13.8)	6,970	6,456
Western	WECC	WECC-DSW	155.3	178.0	174.2		4,788	4,621
		Interconnection Total	*1,000.5*	*1,033.7*	*1,036.3*	*(28.0)*	*19,876*	*18,801*
Texas	ERCOT	ERCOT	381.0	390.0	390.8	(7.8)	10,133	9,886
Eastern	MRO	MRO-Canada	51.6	51.9	52.0		348	348
Eastern	MRO	MRO-U.S.	509.4	596.8	595.9	(16.6)	14,772	14,515
Eastern	NPCC	Ontario	157.8	167.6	163.8		1,859	1,707
Eastern	NPCC	Quebec	207.4	216.8	216.0		142	108
Eastern	NPCC	Maritimes	27.7	20.0	18.1		476	365
Eastern	NPCC	New York	165.9	164.1	151.5		4,179	3,663
Eastern	NPCC	ISO-NE	146.8	149.9	164.7	(53.8)	4,292	2,728
Eastern	RFC	RFC	934.3	906.3	922.6	(55.2)	23,218	21,349
Eastern	SERC	SERC-N	227.0	247.5	246.6		5,959	5,928
Eastern	SERC	SERC-E	232.5	226.8	226.8	(26.3)	5,920	4,869
Eastern	SERC	SERC-W	168.1	171.6	171.1		4,445	4,424
Eastern	SERC	SERC-SE	278.2	299.8	293.4		8,960	8,722
Eastern	SPP	SPP	254.6	267.0	267.0		6,435	6,425
Eastern	FRCC	FRCC	254.6	228.0	227.9		9,058	9,053
		Interconnection Total	*3,615.8*	*3,714.2*	*3,717.2*	*(151.9)*	*90,063*	*84,204*
		National Total:	***4,997.3***	***5,137.9***	***5,144.4***	***(187.6)***	***120,072***	***112,891***

6.5.5 LOWER PENETRATION OF OFFSHORE WIND SENSITIVITY

The previous evaluations were performed with an assumption of 54 GW of offshore wind. Different levels of offshore wind penetration will result in different generation displacement, imports/exports among regions, system losses, etc., resulting in different values for offshore wind. To explore this impact, two additional penetration levels were evaluated assuming the base case fuel prices: 27 GW and 16 GW, or 50% and 30% of 54 GW, respectively.

Table 6-49 presents the results of the case run with 27 GW (50% of 54 GW) of offshore wind, and Table 6-50 shows the results of the case run with 16 GW (30% of 54 GW) of offshore wind. The offshore wind sites in the 27-GW and 16-GW cases were selected proportionally in the four offshore regions. The value of the offshore wind is greater with lower penetration levels, which can be interpreted to mean that earlier offshore wind projects will have a higher impact than later wind projects. This may help justify somewhat higher costs early in the build-out process.

Table 6-49. Summary of Production Costs with 27 GW of Offshore Wind

Inter-connection	NERC Region	NERC Subregion	Load (TWh)	Total Generation (TWh)			Production Cost (M$)	
				No Wind	With Wind	(Offshore)	No Wind	54 GW Wind
Western	WECC	WECC-BC	162.3	158.9	158.4		2,288	2,265
Western	WECC	NWPP	183.6	232.2	235.7	(7.0)	2,308	2,147
Western	WECC	RMPA	79.1	75.7	75.4		1,636	1,627
Western	WECC	BASIN	88.5	108.8	106.9		2,140	2,099
Western	WECC	CALN + CALS	331.6	279.9	281.8	(7.3)	7,464	7,167
Western	WECC	WECC-DSW	155.3	178.3	174.7		4,957	4,867
		Interconnection Total	*1,000.5*	*1,033.8*	*1,036.5*	*(14.3)*	*20,793*	*20,172*
Texas	ERCOT	ERCOT	381.0	389.9	390.7	(4.0)	10,132	10,002
Eastern	MRO	MRO-Canada	51.6	52.2	52.0		355	350
Eastern	MRO	MRO-U.S.	509.4	603.4	602.3	(6.3)	15,138	14,989
Eastern	NPCC	Ontario	157.8	166.5	164.2		1,878	1,774
Eastern	NPCC	Quebec	207.4	216.8	216.3		148	127
Eastern	NPCC	Maritimes	27.7	19.8	18.5		489	401
Eastern	NPCC	New York	165.9	162.3	155.5		4,441	4,116
Eastern	NPCC	ISO-NE	146.8	151.0	159.3	(27.3)	4,733	3,871
Eastern	RFC	RFC	934.3	902.1	910.6	(31.5)	23,709	22,499
Eastern	SERC	SERC-N	227.0	247.8	246.8		6,061	6,025
Eastern	SERC	SERC-E	232.5	237.4	238.4	(13.5)	6,473	5,949
Eastern	SERC	SERC-W	168.1	167.2	166.4		4,505	4,474
Eastern	SERC	SERC-SE	278.2	294.9	291.8		9,029	8,899
Eastern	SPP	SPP	254.6	266.7	494.4		6,528	16,409
Eastern	FRCC	FRCC	254.6	227.9	227.7		9,900	9,890
		Interconnection Total	*3,615.8*	*3,716.0*	*3,944.2*	*(78.6)*	*93,387*	*89,883*
		National Total:	***4,997.2***	***5,139.6***	***5,369.4***	***(97.0)***	***124.3***	***120,057***

Table 6-50. Summary of Production Costs with 16 GW of Offshore Wind

Inter-connection	NERC Region	NERC Subregion	Load (TWh)	Total Generation (TWh)			Production Cost (M$)	
				No Wind	With Wind	(Offshore)	No Wind	54 GW Wind
Western	WECC	WECC-BC	162.3	158.9	158.7		2,288	2,277
Western	WECC	NWPP	183.6	232.2	234.0	(3.6)	2,308	2,227
Western	WECC	RMPA	79.1	75.7	75.6		1,636	1,630
Western	WECC	BASIN	88.5	108.8	108.1		2,140	2,113
Western	WECC	CALN + CALS	331.6	279.9	280.7	(4.5)	7,464	7,285
Western	WECC	WECC-DSW	155.3	178.3	117.1		4,957	4,890
		Interconnection Total	*1,000.5*	*1,033.8*	*1,034.1*		*20,793*	*20,422*
Texas	ERCOT	ERCOT	381.0	389.9	390.0	(1.9)	10,132	10,070
Eastern	MRO	MRO-Canada	51.6	52.2	52.1		355	352
Eastern	MRO	MRO-U.S.	509.4	603.4	602.8	(3.0)	15,138	15,039
Eastern	NPCC	Ontario	157.8	166.5	164.7		1,878	1,797
Eastern	NPCC	Quebec	207.4	216.8	216.4		148	132
Eastern	NPCC	Maritimes	27.7	19.8	19.1		489	438
Eastern	NPCC	New York	165.9	162.3	157.1		4,441	4,190
Eastern	NPCC	ISO-NE	146.8	151.0	157.3	(19.7)	4,733	4,116
Eastern	RFC	RFC	934.3	902.1	907.2	(20.9)	23,709	22,892
Eastern	SERC	SERC-N	227.0	247.8	247.3		6,061	6,040
Eastern	SERC	SERC-E	232.5	237.4	237.6	(4.2)	6,473	6,298
Eastern	SERC	SERC-W	168.1	167.2	166.6		4,505	4,484
Eastern	SERC	SERC-SE	278.2	294.9	293.7		9,029	8,977
Eastern	SPP	SPP	254.6	266.7	266.7		6,528	6,526
Eastern	FRCC	FRCC	254.6	227.9	227.8		9,900	9,893
		Interconnection Total	*3,615.8*	*3,716.0*	*3,716.3*	*(47.8)*	*93,387*	*91,174*
		National Total:	***4,997.2***	***5,139.6***	***5,140.4***	***(57.8)***	***124.3***	***121,666***

6.5.6 Production Cost Conclusions

The economic value of offshore wind in North America was investigated using market-based production simulation software to simulate the operation of integrated electric power systems with offshore wind farms on an hourly basis. The offshore wind power considered includes 76 sites selected from the Pacific, Gulf of Mexico, Great Lakes, and Atlantic regions, with a total capacity of 54 GW.

A base line was established considering a case with no offshore wind production but that represented the expected U.S. North American supply, demand, and transmission grid in 2020. When compared to the case with the offshore wind, the total production cost savings was $7.68 billion annually, with an offshore generation of 187.6 TWh, giving a value of $41.0/MWh from a production cost savings perspective. Estimating the potential impact of CO_2 emission penalties assuming a cost of $20 per metric ton increases the value to $53.5/MWh.

Sensitivity analyses were performed considering future gas price uncertainties and different penetration levels of offshore wind power. If gas prices are 20% higher or 10% lower than the base case projections, the value of offshore wind would change to approximately $47/MWh or $38/MWh, respectively. The value of the offshore wind power would also be greater at lower penetration levels, rising from $41/MWh with 54 GW of offshore wind power to $46/MWh with only 16 GW of offshore wind power capacity.

These results are summarized in Table 6-51.

Table 6-51. Sensitivity of Offshore Wind Value to Penetration Levels

Case Description	Installed Offshore Wind Capacity (GW)	Price of CO_2 Included?	Gas Price Multiplier	Production Cost Savings (B$)	Offshore Wind Generation (TWh)	Value of Offshore Wind ($/MWh)
Base case	**54**	No	1.0	7.68	187.6	40.9
With price of CO_2	**54**	Yes	1.0	10.02	187.6	53.5
High gas price	**54**	No	1.2	8.89	187.6	57.4
Low gas price	**54**	No	0.9	7.18	187.6	38.3
Low offshore wind penetration	**27**	No	1.0	4.26	97.0	43.9
Low offshore wind penetration	**16**	No	1.0	2.65	57.8	45.8

6.6 Section References

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7.0 REGULATORY REVIEW

The opportunity to develop offshore wind in the United States is both large in scale and in the barriers that must be overcome to achieve significant offshore wind development. DOE estimates that the United States has more than 4,000 GW of potential total offshore wind capacity—nearly three times the capacity of the current U.S. fleet of electric generation [1]. Recognizing the size of the offshore wind opportunity, DOE published a *National Offshore Wind Strategy: Creating and Offshore Wind Energy Industry in the United States* [2] to provide a roadmap for increasing wind's contribution to 20% of the U.S. electricity supply by 2030 [3]. Out of 300 GW of capacity required to meet the 20% wind goal, 54 GW of offshore wind deployment totals 18% of total wind capacity. In 2014, after more than 30 years of onshore wind development, 61 GW of wind generation capacity operates in the United States—representing 5.7% of total electric generation capacity in the United States. During the past five years, new wind development on average represented 31% of all new generation capacity built. In wind-rich regions in the plains, northwest, and Midwest, wind development represented 60% of all new generation built in 2013. The onshore wind industry has achieved economies of scale that enables wind to be built cost competitively with traditional generation resources.

To implement the National Offshore Wind Strategy, DOE developed a comprehensive plan to reduce the LCOE and decrease the deployment timelines through the OSWind initiative [3]. OSWind's goal is to promote and accelerate responsible commercial offshore wind development in the United States in both federal and state waters by identifying barriers and systematically exploring possible solutions to these barriers. OSWind provides the framework for multiple research inquiries to methodically address barriers to offshore wind development, including matters of economic cost competitiveness, technical and infrastructure, and regulatory.

The evolution of a regulatory pathway for the development of offshore wind in the United States has been fraught with uncertainty and delays. In November 2001, Cape Wind filed the first U.S. offshore wind permit application with the U.S. Army Corps of Engineers to deploy a meteorological tower to collect wind speed data in Horseshoe Shoal in Nantucket Sound, Massachusetts. More than a dozen years later, Cape Wind has persevered and could be the first commercial-scale offshore wind farm to operate in the United States by 2016. Cape Wind has faced innumerable barriers as the first offshore wind project in the United States, including: changing regulatory regime, challenges securing a power purchase agreement (PPA) for the sale of electricity, 32 legal challenges, and difficulty financing the estimated $2.6 billion project [4]. For offshore wind resources to be developed at scale, the development timeline must continue to be dramatically reduced.

Benefits of Offshore Wind

Offshore wind resource development offers electrical, environmental, and economic benefits. First, developing offshore wind resources provides electrical benefits to consumers and the grid. Offshore wind's electric benefits result from three distinguishing features compared to onshore wind: (1) strength of resource (high CFs); (2) generation during peak power periods, and (3) greater consistency than variable onshore wind resources. In sum, offshore wind produces a larger amount of electricity that is more consistent and dependable when (e.g., hot summer afternoons) and where (e.g., near population centers) electricity is needed most. Combining these electrical qualities, offshore wind is potentially quite valuable to markets on the East Coast. In addition, transmission-constrained regions in New England and the Mid-Atlantic could also benefit from interconnecting offshore wind directly to the power grid, which could relieve congestion, enhance reliability, and serve public policy priorities. Depending on the market where offshore wind is delivered, the higher upfront capital cost of offshore wind could potentially be offset by the benefit of a zero-cost fuel source that would be dispatched ahead of other resources. As a result, offshore wind could create important electrical benefits that should be further evaluated regionally. As a result of these factors, as discussed in Section 6 of NOWEGIS, production cost modeling results suggest that there is an average savings of $41/MWh for deploying 54 GW of offshore wind at 76 sites.

Second, offshore wind offers environmental benefits, including emission-free electricity, greenhouse gas reductions, and its proximity to load centers on the East Coast, which could obviate the need for siting transmission in constrained areas. Some regions are also beginning to evaluate whether the future retirements of coal plants will free up transmission capacity on the grid for offshore wind generation without requiring transmission upgrades. This factor could help reduce the costs of the first generation of offshore wind projects and should be evaluated further by states and regional transmission planners.

Third, offshore wind creates economic development opportunities. As an infrastructure-intensive industry, ports will need to be prepared to support sustained offshore wind development. For example, a $100 million investment is being made to prepare the port in New Bedford, Massachusetts, as the staging area for Cape Wind and future offshore wind projects. Economic development models project that Cape Wind will create an average net addition of 514 jobs in Massachusetts and 1,119 jobs in New England. Another infrastructure need is the specialized vessels required to erect wind turbines and install them on foundations at sea. Although these electric, economic, and environmental benefits hold great promise, the industry continues to face challenges because of the high upfront capital cost and regulatory challenges of offshore wind deployment.

The following regulatory review section of NOWEGIS provides an overview of the key barriers to offshore wind, describes the current federal and state regulatory regimes for interconnecting offshore wind and transmission, describes the current state of the U.S. offshore wind industry in 2014, and explores the policy and regulatory reforms necessary for the interconnection of 54 GW of offshore wind resources.

7.1 The State of Offshore Wind in United States in 2014

Currently, an estimated 5 GW of offshore wind projects are planned in the United States for deployment during the next decade. These first-generation offshore wind projects should benefit from lessons learned from the development of the first offshore wind project in the United States. It is true that many of the legal, technical, and financial challenges that faced Cape Wind will remain for the first generation of offshore wind projects. However, each successive project will benefit in several ways from the development of the previous projects. Today, the federal permitting process has been streamlined in an initiative called "Smart from the Start." Compared to the regulatory regime in 2000, today there is a clearly defined federal regulatory process for leasing land for developing alternative energy projects on the Outer Continental Shelf (OCS). Although there are always opportunities to reduce permitting timelines, it is equally important to create a regulatory regime that provides certainty for regulators, project developers, and the entities providing financing.

7.2 Offshore Wind Opportunities and Barriers

7.2.1 Opportunities for Offshore Wind

The estimated 4,000 GW of offshore wind resource potential is an opportunity for clean energy, economic development, and reduced greenhouse gas emissions. The installation of the first commercial-scale offshore wind project in the United States could be as early as 2016, with approximately 5 GW of announced projects to follow in the next decade. With the deployment of Cape Wind, and the commitment of the Commonwealth of Massachusetts to deploy an additional 2 GW of offshore wind, ISO-NE is positioned to benefit from its tangible and intangible investments in offshore wind development. Advances in technology and policy suggest that the opportunity for offshore wind development is promising for states and regions that are willing to pursue new economic development opportunities.

Offshore Wind Resource

Each year, technological advancement enables us to better understand, locate, and measure the location, strength, and profile of offshore wind resources. Through advanced mesoscale modeling that is correlated with a growing number of samples collected from meteorological towers and other devices, it is now possible to know with a high degree of confidence where the best offshore wind resources are located. In turn, we can measure when offshore wind blows the strongest—usually in the afternoon, which is coincident with peak power needs during the summer—and how it is not only stronger than onshore wind, but more consistent than previously understood. Firms that can collect, analyze, and make wind speed data available help to identify where offshore wind can be deployed with the fewest environmental and existing-use conflicts (see Section 3). High-resolution offshore wind speed maps are increasingly available to the public for states to determine where offshore wind could be developed.

Multi-Purpose GIS-Based Spatial Planning Tool

Similarly, Section 388 of the Energy Policy Act of 2005 directed the BOEM to create a spatial mapping tool to help with responsible resource development on the OCS. With the development of a GIS-based marine information viewer, the BOEM and NOAA collaborated to provide the geospatial framework needed to conduct the coastal and marine spatial planning initiative called for in the President's National Ocean Policy [5]. The MarineCadastre.gov website is a collaborative effort involving federal agencies, regional planning bodies, state entities, and nongovernmental organizations that continues to share information to assist in decision making about the OCS. Through a multiyear stakeholder process, BOEM developed partnerships between and among different agencies and stakeholders that has resulted in a comprehensive planning tool that is available for use by all stakeholders interested in using the OCS [5]. Coupled with newly released mesoscale wind speed data, the MarineCadastre.gov website enables developers and other stakeholders to use 140 data layers to identify lease blocks that are free of conflicts, possess the best wind resources, and are closest to the electric grid. The multipurpose mapping initiative is a tool that can inform decision making related to alternate uses of energy on the OCS.

Regulatory Reforms

Today, the regulatory regime for offshore wind is vastly improved, but it needs to be enhanced further. Following passage of the Energy and Policy Act of 2005, the regulatory authority for permitting all new projects on the OCS was transferred from the U.S. Army Corps of Engineers to the Minerals Management Service (MMS)—known today as the BOEM. This congressional act helped to alleviate confusion in the permitting of renewable energy and traditional oil and gas development in federal jurisdictional waters and leveraged the existing leasing process for oil and gas development on the OCS. Although some of the environmental and public concerns that challenged Cape Wind may persist for future projects, lessons learned from challenges related to siting, environmental permitting, power contract approval, and interconnection challenges can be shared through best management practices between and among regions. This regional knowledge gap means that states and also regions will need to collaborate in innovative ways to overcome the same barriers in Massachusetts.

BOEM continues to work with states to identify wind energy areas that combine siting and environmental permitting in the development process. BOEM also has exercised its agency discretion to implement the National Environmental Policy Act in a way that facilitates the use of tiering, incorporation by reference of studies performed on the OCS, concurrent federal and state environmental reviews, and best management practices—potentially reducing the permitting process from 7 yr to 10 yr down to 4 yr.

Advanced Technology Demonstration Projects

As part of OSWind Initiative, DOE identified dozens of research investment opportunities to address the key barriers to offshore wind. In 2011, DOE awarded $4 million to seven offshore wind demonstration projects. In May 2014, DOE awarded additional funding to three advanced technology demonstration projects to explore innovative ways to reduce costs (see Section 6.1.2). Fishermen's Energy, Dominion, and Principle Power will each receive $47 million toward the design and installation of offshore wind technology that will help reduce costs and decrease permitting timelines. By 2017, the deployment of the first commercial offshore wind farm and deployment of three demonstration projects will provide valuable lessons learned for reducing permitting timelines and reducing the cost of installation of projects in the United States.

Sustainable Policy Support for Offshore Wind

If offshore wind is to be deployed on a gigawatt scale, then durable, sustainable state and federal policies are required to reduce the cost of offshore wind. States with a consistent policy framework that supports the demand for offshore wind development—including infrastructure investment, RPSs that create demand for offshore wind energy, and reduced state leasing fees—will be in a position to benefit from offshore wind. State and regional transmission planners will also need to evaluate how to holistically plan for an efficient transmission grid for onshore and offshore wind that may or may not get built within a given planning horizon. As the potential value of offshore wind continues to be understood, regions and states that develop the first generation of projects will determine whether they can be built cost effectively.

7.2.2 Offshore Wind Barriers

In 2013, DOE commissioned an annual market economic assessment that summarized three significant challenges for offshore wind in the United States [6]: (1) cost competitiveness, (2) technical and infrastructure, and (3) regulatory issues (Table 7-1). These barriers rise and fall in a connected relationship because of the inherent capital intensity and regulatory complexity of building an offshore wind project. These combined barriers create risk—perceived and real—that play a significant role in whether and how much offshore wind will contribute to the 20% wind goal.

Table 7-1. Key Offshore Wind Barriers

Category	Barrier Description
Cost competitiveness	High capital cost High cost of energy produced by offshore wind High financing cost due to risks
Technical and infrastructure	Lack of purpose-built ports and vessels Lack of domestic manufacturing Inexperienced labor Insufficient domestic operations and maintenance capabilities Insufficient offshore transmission infrastructure
Regulatory	Uncertain site-selection process and timeline Fragmented permitting process Environmental and public resistance Uncertain environmental impacts

Although these barriers are formidable, so, too, is the investment in research and development to help reduce costs and decrease permitting timetables for offshore wind development. DOE invested more than $50 million in dozens of research and development projects to reduce these barriers [7]. Specifically, $25 million will be invested in the development of innovative wind turbines and design tools, $18 million toward optimizing wind and electric markets (transmission and planning), and $7.5 million in developing next-generation wind turbine drivetrains.

Because of the infrastructure and technical skills required to build the first offshore wind projects, each region will face many of the same initial infrastructure barriers required to support offshore wind deployment. In Massachusetts, $100 million is being invested in the New Bedford port to support queue-side improvements necessary for the construction of Cape Wind [8]. In addition, local employment training workshops are planned to help develop the skilled workforce required to construct, operate, and maintain the offshore wind projects. Suppliers for the foundations, towers, and wind turbine blades, hubs, and nacelles will establish U.S. manufacturing only after enough demand is demonstrated in the marketplace—perhaps after the first generation of projects are built. As additional states in different regions pursue offshore wind development, important lessons learned can be shared regionally.

As regions confront the high upfront costs and complex regulatory regime, policies that address barriers are required to support offshore wind deployment. By reducing the regulatory barriers and demonstrating the technical capabilities required to install the first commercial-scale project, a region can then seek to achieve cost-efficiencies that will result from economies of scale. In time, financing costs and installation costs in a region will decline with investment in infrastructure and the demonstrated capability to meet a schedule for installation.

The following regulatory review will focus on the key regulatory challenges and advancements as they relates to the potential staging and deployment of offshore wind in the United States.

7.3 Regulatory Overview of Offshore Wind Permitting

Offshore wind development is regulated by multiple federal, state, and local regulatory entities. The purpose of this overview is to provide a summary of the regulatory process for offshore wind development in the United States: (1) site control/leasing, (2) environmental permitting, (3) power contract, and (4) interconnection. Table 7-2 provides a jurisdictional chart for the regulation of offshore wind for each of these four categories.

The following four-part analysis is not meant to be an exhaustive guide to permitting an offshore wind project; rather, these four regulatory requirements are essential elements necessary for the development of offshore wind. States and regions will pursue policy solutions for each regulatory requirement. These four requirements create a framework to determine whether the current regulatory regime is suitable for the interconnection of 54 GW of offshore wind.

Table 7-2. Jurisdictional Chart for the Regulation of Offshore Wind

Jurisdictional Chart for Offshore Wind Regulation	Project in State Jurisdictional Waters	Project in Federal Jurisdictional Waters
Site control/leasing	State lands or administrative offices	BOEM[6]
Environmental permitting	U.S. Army Corps of Engineers is the lead federal agency for permitting in state waters, which will involve the coordination with state and other federal agencies.	BOEM has statutory responsibility for ensuring that the major environmental laws are enforced; other federal agencies are involved as well.
Power contract	State PUC approval	State PUC approval
Interconnection	State PUC or state siting board	FERC

7.3.1 *Site Control*

Offshore wind leasing, siting, and environmental permitting is regulated based upon the location of the project, which determines state or federal jurisdiction. According to the NOWEGIS results, approximately 86% (46 GW) of the 54 GW of offshore wind deploys in federal jurisdictional waters. As a result, site control will be addressed in two subsections. Approximately 77% of 5 GW of first-generation projects are also in the early stages of permitting in federal waters.

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[6] BOEM is governed by the Submerged Lands Act of 1953 and the Outer Continental Shelf Lands Act of 1953.

Federal Water Jurisdiction

Since passage of the Submerged Lands Act and the Outer Continental Shelf Lands Act of 1953, federal law has recognized that states have title to the natural resources up to 3 nmi from the coast in the Atlantic, Arctic, and Pacific oceans, and the Gulf of Mexico [9]. Beyond the 3-nmi limit, the U.S. government holds exclusive title to submerged lands on the OCS out to 12 nmi.

In 2005, the Energy Policy Act established the MMS as the federal agency responsible for leasing lands and enforcement of federal environmental laws on the OCS. Since this time, the Department of the Interior (DOI) reorganized MMS and the BOEM and Regulatory Enforcement to BOEM to physically separate the entities that collect lease revenues, conduct lease sales, and perform the safety and environmental enforcement functions. Today, DOI separates the leasing duties performed by BOEM from the safety and enforcement responsibilities of the Bureau of Safety and Environmental Enforcement.

Prior to 2008, no regulatory process existed for the development of alternative energy resources—including hydrokinetic, offshore wind, and wave energy technology—on the OCS. The best a developer could seek was an interim policy research lease that was restricted to data collection for a 5-yr period. Five such leases were awarded during this time. Blue Water Wind received two interim policy leases—one in Delaware and one in New Jersey, both of which have been relinquished. Additionally, Deepwater Wind and Fishermen's Energy received interim policy leases for New Jersey. As interest in offshore wind moved from technical and research projects to commercial projects, new regulations were needed to facilitate development.

In 2008, DOI announced the Renewable Energy Program to systematically create a regulatory pathway for offshore wind siting and permitting on the OCS [10]. In 2008, DOI released regulations governing renewable energy activity on the OCS [11]. The regulations were important because they proposed the first permitting requirements for commercial-scale offshore wind. The interim policy had merely permitted research and survey activities during a 5-yr lease term. The 2009 regulations created a comprehensive regulatory process, which continues to be improved. One area that has shown improvement is in potential communication gaps among multiple federal agencies with jurisdiction over the OCS. Through formal agreements between and among six federal agencies, the federal government built formal and informal relationships to promote offshore wind development.

BOEM's Smart from the Start

In 2010, DOI launched the Smart from the Start wind energy initiative for the Atlantic OCS to facilitate siting, leasing, and constructing new projects that are both responsible and rapidly developed [12]. A list of the policies and criteria for projects is provided in Figure 7-1. BOEM deserves credit for initiating and implementing the Smart from the Start initiative because it has reduced needless red tape, identified resources, and realigned the BOEM's core mission to include harnessing the development of both conventional oil and gas as well as renewable energy on the OCS. Smart from the Start builds upon lessons learned from solar development on public lands where public lands were prescreened to minimize environmental and use conflicts to accelerate the development of solar projects on federal lands in the West. The initiative established principles that helped provide direction to the multiple federal agencies involved in regulating offshore wind development without prescribing a regulatory checklist that had to be followed.

Smart from the Smart resulted in the most significant regulatory improvements in the planning and analysis phase of the BOEM regulatory process. The identification of WEAs had two important benefits. First, BOEM prescreened large resource zones (WEAs) that are suitable for offshore wind development on the OCS. Second, this prescreening process helps facilitate site control during the lease process. Prior to Smart from the Start, a developer risked expending significant resources characterizing the potential environmental impacts of an offshore wind farm without yet having legal title to a site. WEAs helped demonstrate the recently approved regulations for gaining site control by developers in advance of extensive environmental analysis.

Smart from the Start Policies and Criteria

- **Consult stakeholder early and involve them in the planning, zoning and siting.**
- **Collect and use geospatial information to categorize risk of resource conflicts.**
- **Avoid land and wildlife conservation conflicts (including national parks and other protected areas) and prioritize development in previously disturbed areas.**
- **Avoid cultural resource conflicts (historic sites, tribal resources, etc.).**
- **Identify excellent renewable energy resource values.**
- **Establish, when possible, prescreened resource zones for development.**
- **Incentivize resource zone development with priority approvals and access to transmission.**
- **Consider renewable energy zones or development sites that optimize the use of the grid.**
- **Maximize the use of existing infrastructure, including transmission and roads.**
- **Employ "mitigation that matters" (durable and planned conservation improvement at larger scales).**
- **Where zoning is not feasible (as in much of the Eastern Interconnection), use siting criteria based on the above principles.**

***From Smart from the Start website* [13]**

Figure 7-1 Smart from the Start

Since 2009, BOEM has identified six WEAs along the Atlantic OCS for offshore wind development. As discussed in Section 7.4.2 on Environmental Permitting, identifying WEAs enabled BOEM to perform environmental assessments, which generally take less time and resources than a complete environmental impact statement under the National Environmental Policy Act (NEPA). Given the complexity of the environmental permitting process, a deliberate effort to prescreen WEAs for resource development has enabled the elimination of one resource-intensive step in the NEPA process.

Smart from the Start also emphasizes the importance of federal and state communication throughout the BOEM regulatory process. Extensive planning includes deliberate and repeated stakeholder consultations and the creation of state offshore wind task forces that were initiated at the request of governors. Recognizing the importance of communication and consultation between federal and state agencies, the U.S. Secretary of Interior directed BOEM to initiate state task forces in each state with sufficient interest. In the end, more than 10 states responded by creating state offshore wind task forces to help encourage communication, coordination, and collaboration where permissible. As a result, task forces were venues for federal and state staff to informally discuss important state environmental, cultural, historic, tribal, ecological, and other resources *before* initiating a formal environmental permitting process. Early consultation in the planning, zoning, and siting process are important steps in developing working relationships with an array of stakeholders. Likewise, BOEM continues to perform outreach to states and regions that are exploring the potential for offshore wind.

<u>BOEM Stages of Renewable Energy Development</u>

<u>Leasing</u>

In 2011, BOEM finalized its offshore wind lease process for noncompetitive and competitive leasing [14]. BOEM's regulatory process includes (1) planning and analysis, (2) leasing, (3) site assessment, and (4) commercial development. (See Figure 7-2.) To determine competitive interest, BOEM publishes a call for information and nominations in the Federal Register to determine if there is competitive interest in certain lease blocks. After a 60-d comment period, BOEM determines if there is competitive interest. If BOEM makes a determination of no competitive interest, then the lease is awarded to an entity that agrees to a 5-yr site assessment term and a 25-yr operations term. The first leases awarded were done so after

BOEM determined that there was no competitive interest. Under this regulation, BOEM enters into a noncompetitive lease for a rental fee of $3 per acre for a set term.

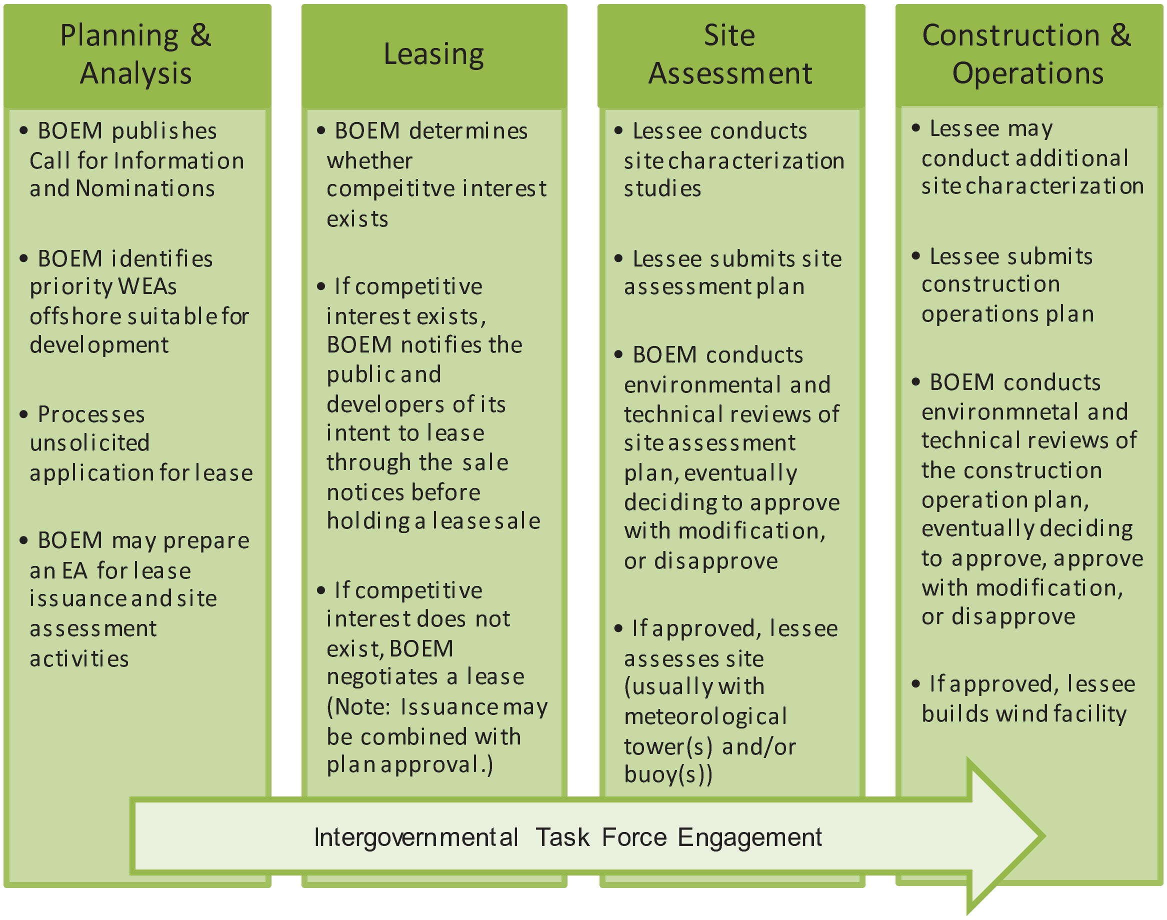

Figure 7-2. BOEM regulatory process

<u>Non-Competitive Leases</u>

The federal government has executed two non-competitive leases for offshore wind development. In 2010, Secretary of Interior entered into the first commercial offshore wind lease in the United States with Cape Wind. The lease grants Cape Wind a 5 year site assessment term and a 28 year operations term. Annual rent for Cape Wind is $3 per acre, or $88,278, and royalty payments will be paid based on the generation of wholesale power from the project.

In 2012, NRG Bluewater Wind acquired lease rights to develop an offshore wind project off the coast of Delaware through the noncompetitive process. NRG Bluewater's Mid-Atlantic Wind Park received a 5 year site assessment term and a 25 year operations term. The rent due to the U.S. Treasury for this project totals $289,290. NRG Bluewater's project in Delaware is currently on hold after determination that it could not find an investor in the project. As a result, Delmarva Power cancelled the PPA for 200 MW. NRG Bluewater continues to hold the lease rights for this area, but the project does not have a power contract to move forward with offshore wind development at this time. NRG's CEO David Crane expressed his continued support for offshore wind on the east coast, and the need for stable public policy to support the industry. Crane cited the failure of Congress to extend production and investment tax credits and the lack of a federal loan guarantee program for offshore wind as the reasons for not being able to find a financing partner for the project [15].

Competitive Lease Sales

Upon determination of competitive interest, BOEM proceeds to award the lease to a bidder through a competitive auction process. BOEM has successfully overseen two competitive lease sales: Rhode Island/Massachusetts in July 2013 and Virginia in September 2013. The commercial lease gives the lessee exclusive right to subsequently request permission from BOEM to develop the leasehold. The lease does not give the lessee the right to construct any facilities, but merely grants the lessee the right to develop its Site Assessment Plan and Construction Operation Plan that must be approved by BOEM.

In 2013, BOEM finalized the regulations for Site Assessment and General Activities plans [16]. These regulations are untested, but their completion marks a milestone for the initial regulatory pathway for offshore wind in the United States. With announcement of DOE's Advanced Technology Demonstration projects—Fishermen Energy's Atlantic City Wind Farm, Dominion's Offshore Wind Technology Assessment Program and Principal Power's WindFloat Pacific project—these projects will join Cape Wind and Deepwater's Block Island projects in navigating these regulations.

Although this regulatory process for gaining site control is lengthy, it has been improved from the initial Interim Policy. Still, efficiencies in each step of the BOEM regulatory process will need to be made in order to deploy significant amounts of offshore wind.

Site Control in State Jurisdictional Waters

The NOWEGIS results suggest that approximately 8 GW of offshore wind could be developed in Texas and the Great Lakes in an economically efficient manner. There is an estimated 750 GW of offshore wind potential in U.S. state jurisdictional waters [3]. Although 8 GW represents a smaller portion of total offshore wind developed in the 20% wind scenario, state siting is demonstrably more straightforward than the federal leasing on the OCS. Site control for offshore wind in state jurisdictional waters is a matter of state law. On the OCS, state jurisdictional waters extend three nautical miles for every state with the exception of Texas and west coast of Florida. In the eight states bordering the Great Lakes, title to the submerged lands under the Great Lakes is governed by state law. For the staging of offshore wind deployment, approximately 16% (8 GW) of the total 54 GW deploys in state jurisdictional waters. This includes approximately 2.8 GW in Texas and 6 GW in the Great Lakes.

Although siting is but one step in the offshore wind development process, obtaining a lease or site control from a state can be an expedited process compared to even the improved BOEM federal leasing process. Although there are generally fewer offshore wind resources with potentially higher conflicts in state waters, siting in state jurisdictional waters offers numerous benefits. The first benefit is that a state controls the complexity of the leasing process, which enables states with a strong policy preference for offshore wind to develop an efficient leasing process. In these states, leasing will be pursued through the state lands office, Department of Administration or some other instrumentality of the state that will grant a lease for use of the submerged lands. In Texas, for example, the General Lands Office (GLO) has the authority to negotiate a lease for use of state submerged lands. The Texas GLO is a model for a one stop permitting process. In New Jersey, North Carolina and Rhode Island, for example, the Department of Administration controls state siting and is responsible for leasing in state waters.

States also possess the ability to identify offshore wind as a public policy priority and can use the state siting, leasing and permitting process to encourage development of offshore wind. There are several examples of states supporting the development of offshore wind—most notably where the first generation of demonstration and commercial projects are currently planned. In Rhode Island, the state entered into a joint development agreement (JDA) with Deepwater Wind to develop a 30 MW Block Island Wind Farm to provide a stable source of electricity to the Block Island community. Importantly, the JDA committed the state to certain obligations to make reasonable efforts to support siting and permitting of the 30 MW Block Island Wind Farm, initially, and the 384 MW commercial scale project. The agreement also commits the state to expedite permitting and approvals throughout the process and to help support the developer secure one or more power purchase agreement to support the projects. By focusing on a smaller project to serve a discrete need for electrical services on Block Island, the state is demonstrating its ability to site and permit a larger commercial scale project in the longer term. Importantly, the development process in Rhode Island combines both the siting and the permitting process so that efficiencies may be achieved as well. This is similar to BOEM's use of Wind Energy Areas to combine siting and environmental permitting to potentially reduce development timelines. In New Jersey, the Atlantic Wind Farm developed by Fishermen's Energy is within the 3 nautical mile reach for state jurisdiction.

In the Great Lakes states, a consortium of five states is exploring how to promote efficient, expeditious, orderly and responsible offshore wind development. In 2012, Pennsylvania, Illinois, Michigan, Minnesota and New York signed an MOU with ten federal agencies outlining their respective responsibilities, point of contacts and their commitment to collaborate on creation of a regulatory roadmap within the next 15 months. The Great Lakes Offshore Wind Energy Consortium is an example of the use of an MOU to develop both formal and informal procedures for collaboration across state and federal jurisdictions. Although this MOU does not create demand for offshore wind, nor does it address siting issues, it does recognize the significant role environmental permitting plays in developing a potential offshore wind resource in the Great Lakes in an environmentally responsible manner.

7.3.2 Environmental Permitting

The second regulatory requirement for offshore wind is state and federal environmental permitting. In order to deploy significant amounts of offshore wind, a more efficient environmental permitting process is needed without sacrificing the enforcement of environmental statutes. Permitting Cape Wind took over a dozen years to complete. This is substantially longer than the estimated 7-10 years that was initially recognized as a substantial barrier by the Smart from the Start program

Environmental permitting of large infrastructure projects is complicated by a number of factors. Although siting projects in state jurisdictional waters can be a simpler process, the same cannot be said for environmental permitting where overlapping federal and state jurisdictions complicate the environmental review process. An in depth discussion of the federal and state environmental laws, regulations and rules is out of the scope of this report; however, BOEM has adopted several regulatory reforms for environmental permitting that could potentially reduce permitting timelines.

BOEM has the statutory responsibility to assess the potential environmental impacts of renewable energy development on OCS resources. Through implementation of the National Environmental Policy Act (NEPA) more than a dozen federal environmental statutes and executive orders must be satisfied in order to successfully permit an offshore wind project in federal jurisdictional waters [17]. NEPA requires BOEM to determine if an offshore wind project constitutes a major federal action that significantly affects the human and natural environment [18]. Through the NEPA process, BOEM must coordinate with Federal, state and local agencies, tribal governments and other stakeholders interested in commercial and recreational fisheries, protection of marine and coastal habitats, designation and protection of marine areas with specific significance because of conservation, ecological, recreational, historical, scientific, cultural, archeological or aesthetic qualities. Because NEPA is a procedural statute, there are no time requirements for completing the review. As a result, the NEPA process can be lengthy depending on the review required. However, the lead federal agency has significant discretion to determine the type and level of analysis required of the proposed action. By collecting and developing data sets on the environmental, ecological, cultural and other resources that could potentially be impacted by offshore wind development, state, federal and other stakeholders can increase the knowledge quotient to determine if impacts are likely.

States and universities are working to collect marine and ecological data that could help inform any environmental impact assessment from offshore wind development. In North Carolina, the General Assembly asked the University of North Carolina (UNC) to perform an offshore wind feasibility study [19][20]. In March 2014, UNC deployed two buoys 20 and 40 miles off the coast of North Carolina to collect wind, temperature and barometric pressure data for offshore wind research. In Maryland and Virginia, physical equipment has been acquired to perform geophysical surveys and collect wind energy data that will help provide information necessary for the regulatory process. In April of 2014, the Maryland Energy Agency issued a request for information on deployment of a meteorological tower to collect information on the OCS off the coast of Maryland [21]. In May of 2014, Maryland published the results from a high resolution geophysical study conducted on the OCS in order to help jump start development activities [22].

Environmental Assessments

The first step in the NEPA analysis is to determine if the federal action will constitute a significant effect on the quality of the human environment. This review is called an environmental assessment (EA). If a finding of no significant impact is made—i.e. the impacts are not significant—then a brief concise evaluation of the impacts and mitigating alternatives can be written in a concise EA report. Depending on the potential analysis and impacts, an EA could take as little as 12 months to complete. If the proposed action has significant environmental impacts, a more thorough evaluation of the proposed action, need, and potential alternatives will be evaluated in a lengthy independent evaluation called an environmental impact statement (EIS). A full EIS is a time- and resource-intensive process that can take 2 yr to 4 yr or longer, depending on the impacts of the proposed action.

Programmatic EIS

Federal agencies can use their discretion to conduct programmatic environmental impact statement reviews that analyze similar potential environmental impacts across a broad geographic region. For example, the U.S. Bureau of Land Management has issued programmatic EISs for solar and wind development on public lands in the West. In 2007, BOEM drafted a programmatic EIS for alternative energy development and production on the OCS. A programmatic EIS establishes best management practices that may be applied across geographies for all projects, and it enables EAs to build, or tier, off the previous record that was developed more broadly. For example, subsequent EAs can be conducted that might tier or incorporate by reference previous data collected in the programmatic EIS. In December 2007, the record of decision for the programmatic EIS on the OCS was published recommending the promulgation of regulations to govern all alternative energy development and use on the OCS.

Research Leases

BOEM regulations also allow for the application of research leases for offshore wind development [23][24]. In February 2013, the Commonwealth of Virginia's Department of Mines, Minerals and Energy submitted a research lease application to BOEM for the installation and operation of two 6-MW turbines, ancillary metocean facilities, a meteorological tower or buoy, and associated cabling to shore outside of the Virginia WEA. Dominion Virginia Power's Virginia Offshore Wind Technology Assessment Program (VOWTAP) received one of three $47 million grants for advanced technology demonstration projects in May 2014. The development of VOWTAP under BOEM's research lease will serve as templates for surveys, methodologies, and plans required by the BOEM regulatory process. In addition, the Commonwealth of Virginia applied for an application for a research lease for a meteorological tower in the Virginia WEA [25]. Both research leases could be issued as early as the summer of 2014.

Smart from the Start: Wind Energy Areas

By identifying WEAs, Smart from the Start helped leverage BOEM's considerable discretion to reduce the potential for two lengthy EIS processes down to one project-specific EIS. By reducing the environmental permitting from two EIS evaluations to an EA plus a site-specific EIS, BOEM helped to reduce permitting timelines for the mid-Atlantic. BOEM is working with states presently to identify wind resource zones so that the states can select the offshore wind developer in a seamless process. Among the announced commercial projects such as Cape Wind and Block Island Wind Farm, and the three demonstration projects, state and federal agencies are gaining experience with permitting. BOEM executed on this strategy to reduce regulatory timelines by identifying environmental impacts across multiple site locations for the Mid-Atlantic WEA.

Intergovernmental Coordination

Formally, five MOUs were signed to ensure federal collaboration on offshore wind development on the OCS (See Figure 7-3). In 2009, DOI and the Federal Energy Regulatory Commission (FERC) signed an MOU clearly delineating the responsibilities between the two federal agencies [26]. That same year, BOEM and the U.S. Fish and Wildlife Service signed an MOU to strengthen migratory bird conservation through enhanced collaboration between the two federal agencies [27]. In 2009, BOEM released the Renewable Energy Framework governing renewable energy planning, leasing, and development authorization processes and its procedures for allowing alternate uses of existing OCS facilities [28][29]. In 2010, DOI and the DOE signed an MOU to collaborate on prioritizing and facilitating the environmentally responsible deployment of commercial-scale offshore wind and marine hydrokinetic energy development on the OCS [30]. In 2011, DOI clarified the roles and responsibilities of the U.S. Coast Guard and DOI as it pertains to coordination and notification of offshore wind development activities on the OCS [31]. In 2012, the U.S. Department of Defense and DOI signed the Renewable Energy Partnership Plan that, among other things, encourages ongoing communication with the U.S. Department of Defense to identify mission compatibility issues as well as opportunities where renewable energy development could enhance national security [32].

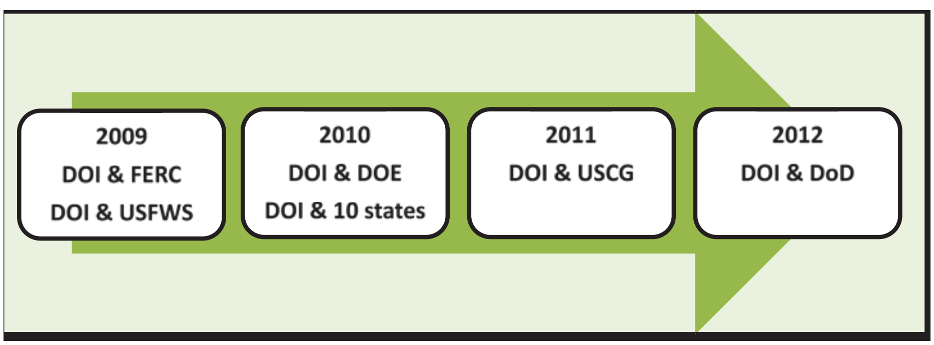

Figure 7-3. MOU signed to promote offshore wind on OCS

Intergovernmental coordination has been encouraged and facilitated by these formal MOUs. By aligning the leadership within federal agencies, agency staff work to coordinate and communicate across their individual departments informally. In fact, some employees at DOE have rotated to DOI and other agencies to ensure that federal employees could work across regulatory jurisdictions.

The collaboration and coordination required to conduct the state and federal environmental processes is extensive, expensive, and often time consuming. Although the first set of commercial and demonstration projects continue to move through state and federal environmental permitting, lessons learned in and among regions should be shared across all stakeholders.

7.3.3 POWER CONTRACT

A contract for power, or PPA, is an essential step in the development process of an offshore wind project that requires regulatory approval. Simply put, a PPA ensures that an energy project receives payment for the generation resource. PPAs are approved by state public utilities commissions (PUCs) that have a statutory duty to regulate the retail sale of electricity. Although this is regulated in different ways in different states, the approval process for an offshore wind PPA is similar across states.

Traditionally, utilities perform integrated resource planning to determine the resources that are required to meet the needs of their customers. Under this regulatory compact with a state, utilities have the authority to build power plants or purchase power from third-party developers. Most states require utilities to develop or buy power that is at the least cost available to their customers. This least-cost mandate varies across jurisdictions, but it is a reflection of the public policy priorities of a state.

In states that are pursuing offshore wind development, the traditional cost-benefit analysis has been modified by state law to support renewable energy or offshore wind development. States have done this in a number of ways. The most common policy examples of this are RPSs. RPS laws mandate the procurement of certain resource types to promote certain public policy priorities. Currently 29 states and the District of Columbia have RPS laws, and another 8 states have voluntary goals for renewable energy procurement [33]. In general, one megawatt hour of renewable energy generated creates one renewable energy certificate (REC) that represents the environmental attributes for the resource.

RPSs

By creating demand for renewable energy resources, the NOWEGIS results indicate the deployment of offshore wind in states with either an RPS or a voluntary goal. Several states have only an RPS requirement for general renewable energy resources (Illinois, Indiana, Maine, Massachusetts, Michigan, New York, Ohio, Pennsylvania, Rhode Island, Wisconsin, and Texas), and only Virginia has a voluntary goal. Delaware created a REC multiplier for offshore wind generation that allows RECs to receive 350% of the value of a general REC, which was designed to make offshore wind cost competitive. It should be noted that although Massachusetts does not have either a carve-out or a REC multiplier, it is the only state with a voluntary offshore wind goal (2,000 MW).

Carve-Outs

Other states have created a carve-out for offshore wind, which specifically mandates a certain amount of offshore wind resources. New Jersey, Maryland, and Maine each adopted RPS laws with offshore wind carve-outs for certain amounts of offshore wind. In Maryland, the Maryland Offshore Wind Energy Act of 2013 broadens the set of benefits that may be considered in the cost-benefit analysis and establishes a customer cost protection cap of $1.50/month for the 200 MW. The Maine Wind Energy Act established a 300-MW offshore wind carve-out that must be met by 2020 and further directed the PUC to hold a competitive process to award a long-term PPA for an offshore wind pilot project. Maine further established the policy of extending the offshore wind RECs (ORECs) to support 5 GW of offshore wind by 2030. In New Jersey, the legislature passed the New Jersey Offshore Wind Economic Development Act to create guaranteed income to offshore wind projects. Through a required “carve-out” for ORECs from the overall RPS requirement, the legislature created demand for up to 1,100 MW of offshore wind energy. The New Jersey legislature broadened the traditional cost-benefit analysis to include a comprehensive net benefits analysis and also created a mechanism to ensure that application for ORECs is a cost-competitive process overseen by the New Jersey Board of Public Utilities.

Long-Term PPAs

In Massachusetts, Cape Wind secured a 15-year PPA with National Grid for 50% of the output and a 15-year PPA with NSTAR for 27.5% of the output. The price for the PPA is $187/MWh—representing a premium above market rates. However, notwithstanding the premium, analysis performed by Charles River & Associates demonstrated that Cape Wind will be dispatched ahead of other generators because of the zero fuel cost of wind generation. According to analysis performed by Charles River & Associates, even with a premium PPA price of $187/MWh, Cape Wind electricity generation will lower the wholesale electric power prices by $1.86/MWh on average throughout 25 yr—totaling $286 million in annual savings or $7.2 billion in savings during the same 25-yr-period in ISO-NE without Cape Wind. These results are consistent with the potential cost savings demonstrated by the NOWEGIS report in previous sections.

It is important to note that none of the Great Lakes states have passed an offshore wind carve-out or a REC multiplier to promote offshore wind. In contrast to the Atlantic Coast projects, Texas and the Great Lakes states have focused on improvements to the regulatory process for siting and permitting offshore wind.

7.3.4 INTERCONNECTION

The fourth regulatory requirement for offshore wind deployment is the interconnection process. Because of the high capital cost and the desire to develop the most cost-efficient generation and transmission system possible, this section will explore the regulatory pathways and options for interconnecting gigawatt-scale offshore wind. As discussed in Section 7.2.3, site control and leasing is regulated by BOEM. Although obtaining a commercial lease and a permit can be a lengthy process, so, too, can the interconnection process. A developer of an offshore wind project is required to follow federal interconnection regulations as overseen by FERC. Interconnecting transmission is technically straightforward, but its impacts raise questions about cost. Because of the difference in market structure throughout the competitive markets and the vertically integrated utility territories, some background on FERC jurisdiction is required.

OVERVIEW OF FERC JURISDICTION

The wholesale of electricity generated by offshore wind is under the jurisdiction of FERC. In the United States, the generation, distribution, and transmission of electricity is a highly regulated form of commerce. Although different models of competition exist in different regions in the United States, the federal government regulates the transmission and wholesale sales of electricity in interstate commerce. States regulate the generation, distribution, and transmission of electricity that resides within a single state jurisdiction. Prior to the 1990s, vertically integrated utilities operated independently from one another, resulting in few bilateral transfers of wholesale electricity. Since the 1990s, electric and gas markets have become more transparent and more competitive throughout the United States based on federal policy as determined by Congress and implemented by FERC. FERC Order 888 [34] and Order 889 [35] established principles of nondiscrimination and open access to the transmission system to create markets that help facilitate the exchange of power between and among parties across the transmission system.

These federal policies have sought to increase competition, ensure open access and nondiscrimination to the transmission system, and thereby decrease the costs of electricity to consumers. Although this trend toward increased competition is often referred to as the “deregulation” of the wholesale gas and electric markets, both the electric and gas markets remain highly regulated for many important policy reasons. FERC continues to regulate interstate gas and interstate electric transmission among other statutory responsibilities, but is encouraging greater competition within a particular regional market design.

In 2010, FERC issued Order 1000 to implement reforms designed to further increase transparency and reduce the opportunity for transmission to be used in a discriminatory manner. At the heart of Order 1000 is how regional transmission planning must occur across FERC jurisdictional utilities and how transmission projects will be paid for if they are selected in the regional transmission planning process.

Cost Allocation

Whether a transmission project is in a competitive market or a vertically integrated utility territory, transmission projects may be paid for in one of three ways: (1) the generator pays for transmission services and includes the cost in the PPA; (2) users pay for transmission services; or (3) all users of the transmission system pay for the transmission project. Depending on the market structure, how the project will be paid for—cost allocation—can be very broad (across a utility territory or across an RTO) or very narrow (the generator or the user of the electricity pays).

Market Structure

Depending on the type of market structure, several possible procedures can be implemented to interconnect a transmission project serving an offshore wind project. Market structure is important, because it determines how transmission projects are planned and paid for via one of two scenarios: (1) competitive markets with multiple market participants or (2) a vertically integrated utility. Competitive markets are operated across multiple states by RTOs or within one state jurisdiction by an ISO. A vertically integrated utility will have its own FERC approved process for interconnection, which is codified in its tariff (an open-access transmission tariff).

Vertically-Integrated Utility Development

Under a vertically integrated utility jurisdiction, a project may be initiated by either the utility or a third party. If the offshore wind project is initiated by the utility to develop, the project generally would need to go through the state PUC or siting board process that demonstrates the project is needed within their integrated resource plan pursuant to state law. Although the regulatory approval process (e.g., via obtaining a Certificate of Public Convenience and Need) varies by name and procedure across states, a utility offshore wind project must meet the regulatory standard for "need" to serve the using and consuming public in that state.

Because of the traditional least-cost mandate for generation development and the high capital costs for offshore wind, without some policy impetus for offshore wind it might be difficult for a vertically integrated utility to justify the increased costs of offshore wind without a policy justification. In most scenarios, the demonstrated need for generation would most likely be met with a lower cost resource than offshore wind. However, if there is a policy directive or a cost justification, then offshore wind generation and transmission assets could be included in a utility's rate base for cost recovery from all customers.

Third-Party Development

A third-party developer proposing a project in a vertically integrated utility jurisdiction would likewise need to follow the interconnection procedures in the FERC-approved open-access transmission tariff. A third-party developer is required to follow the generator interconnection process (GIP), which could take 12 months to 24 months and requires the generator to pay for any needed transmission upgrades. The GIP process is discussed below, but it usually results in significant additional costs being placed upon the developer whose price must absorb the cost of transmission interconnection. For this reason, identifying lease blocks that are close in proximity to the interconnection point and minimizing transmission costs is critical for these projects to be successful. Currently, no commercial-scale offshore wind projects are planned with an interconnection to a vertically integrated utility.

RTOs

Six RTOs in the United States, shown in Figure 7-4, facilitate the operation of competitive wholesale electricity markets. The regions in the United States that are not served by RTOs—the West and the southeast generally—have varying models of cost-of-service rate-making whereby a utility is responsible for planning both the generation and the transmission system. Traditional utility planning tends to focus on the reliability of the electric grid, and historically it has resulted in few transfers of wholesale power between utilities.

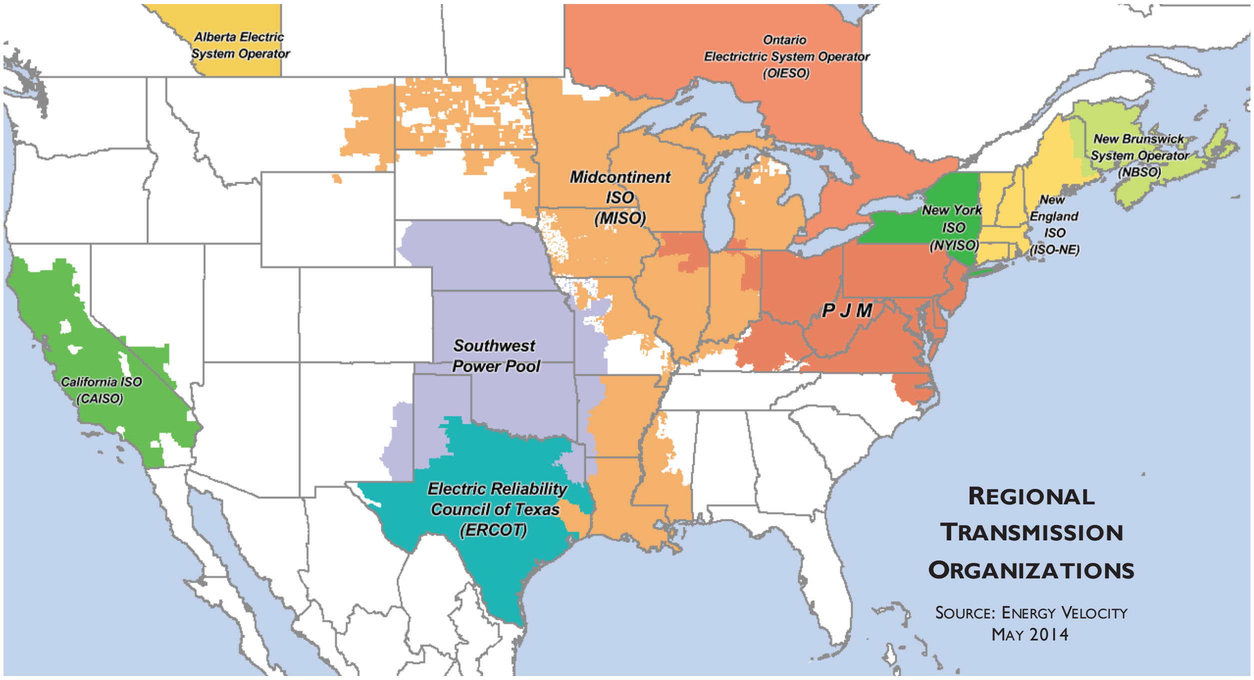

Figure 7-4. RTOs

As noted in previous sections, the production cost simulations identified the most cost-efficient markets in several regions to deploy offshore wind, namely the Atlantic Coast, the Gulf of Mexico, the Great Lakes, and the Pacific Coast.

All of these areas fall under the jurisdiction of FERC for interconnection procedures, with the exception of ERCOT in the Gulf of Mexico, which is under the sole jurisdiction of Texas. In either case, there are three general needs for transmission development.

7.3.5 TRANSMISSION PROJECTS

Reliability Projects

Traditional transmission development is pursued by utilities that serve customers with the principal job of ensuring that the electric grid is reliable. Utilities may invest in any number of transmission projects to ensure that the grid is robust and that electricity will be delivered to customers within milliseconds of when it is generated. NERC regulates national reliability standards in the United States. Transmission projects that serve wholesale customers or more than one utility are regulated by FERC. However, transmission projects that serve retail customers of a single utility are the sole jurisdiction of state PUCs that are responsible for ensuring that customers are served in a way that is consistent with priorities established by state law (reliability, least cost, etc.). Reliability projects are the first priority for transmission planning.

Economic Transmission Projects

A second category of priority for transmission planning is developing transmission projects that are economic or cost-effective. Transmission projects that are economic either deliver lower cost electricity or relieve congestion in a way that produces a demonstrated benefit to the grid and customers. Utilities have different ways of measuring whether projects are economical through avoided cost rates, cost of service, or a cost-benefit analysis. In the traditional utility business model, economic projects are governed by state law and implemented by state PUCs. The result of the cost-benefit analysis can be specifically dictated by statute or it can be entirely left to the discretion of the PUC. In Maryland, the state legislature directed the Public Service Commission to consider a broad set of benefits. In other states, PUCs may be more restricted as to the types of benefits that may be considered in the cost-benefit analysis or they may have unfettered discretion to consider a broad range of benefits.

Public Policy Transmission Projects

A third category of transmission projects are those developed to further important public policy priorities as determined by state law. Public policies that support the development of generation or transmission projects include state RPSs, state laws maximizing the use of rights of way for transmission siting, energy efficiency standards, laws specifying the order for which generation is prioritized (loading order), greenhouse gas reduction laws, and other public health and environmental priorities. As the mix of generation and transmission changes because of a number of factors (aging infrastructure, macroeconomic factors such as low gas prices, and more strict air and water pollution standards), older, less-efficient generation plants will continue to be retired and replaced with some combination of new generation and/or transmission assets.

As generation is retired and replaced with newer technologies, transmission planners work to develop scenarios for how to ensure that planning is completed in a way that is reliable, cost-efficient, and promotes important public policies. Whether and how this generation is replaced could determine whether offshore wind can be seamlessly interconnected to the existing grid through radial lines without expensive upgrades. Offshore wind energy generated near major population centers and injected directly into major load centers could provide an opportunity to utilize existing infrastructure by interconnecting radial transmission lines to offshore wind resources.

7.3.6 TRANSMISSION PLANNING TO SUPPORT OFFSHORE WIND

Developing transmission to support offshore wind generation is not likely to be supported by traditional reliability requirements alone. The NOWEGIS production cost simulations suggest that there may be a net economic benefit for producing electricity from 54 GW of offshore wind, but with the projected high installed costs ($6,000/kW) and technical and infrastructure barriers, transmission planners will need to complete additional studies on a regional basis to see if benefits outweigh costs of building transmission to support offshore wind. Transmission planners need policy direction to take into account offshore wind as they plan the transmission system.

RPS laws that create a public policy priority for offshore wind are the primary demand driver for offshore wind and the accompanying transmission in the United States. Six RPS laws that have been enacted that provide demand support for offshore wind. This demand support can be developed in different forms, including specific carve-outs or requirements for the procurement of offshore wind in some set amount (for example, GW or a percentage of total sales of electricity). Other state models include the authorization of above-market payments for PPAs outside of the least-cost planning framework. States can also broaden the enumerated benefits of deploying offshore wind, including the rationale of job creation, greenhouse gas reductions, energy security, or the notion of competitive solicitations for generation resources. When a state enacts a policy that supports offshore wind, transmission planners can assume the generation will be built.

There are three ways to plan and develop transmission needed for offshore wind projects under the current regulatory regime: (1) GIP, (2) merchant transmission, and (3) regional planning projects in RTOs.

GIP

In the initial years of deployment, it is likely that offshore wind development will use interconnection through the GIP to ensure that transmission is planned and developed. Although this will ensure that all needed upgrades are planned and developed, it requires the generator to pay for 100% of the cost of the transmission line connecting to the grid and any upgrades that could be required as a result of the new generation. Notwithstanding the FERC pro forma open-access transmission tariff requirement that a generator be reimbursed after the generation is commercially operational, interconnection through the GIP creates a significant cost burden on the offshore wind developer, which increases the total cost of offshore wind. The GIP will most likely be used to interconnect a large portion, if not all, of the first several gigawatts of offshore wind in the United States absent a different policy mechanism for the ownership and development of a coordinated backbone or grid. A status-quo policy will likely result in a combination of many radial connections or split connections to the electric grid, which could complicate both landfall connections and transmission planning along the Atlantic Coast. However, depending on a number of factors, including proximity of the wind farms to one another, radial lines may be the most optimal electrical connection—albeit expensive for the generators.

The Texas Competitive Renewable Energy Zones (CREZ) model for onshore wind development effectively dealt with this issue by determining that every electrical customer in the state should pay for a share of the more than 3,600 mi of transmission determined to be needed to most efficiently integrate expected wind development. The Texas CREZ transmission lines have integrated more than 18 GW of onshore wind at a cost that is competitive and paid for by all customers in the Texas market. Additional states could determine that CREZ zones could be established to help reduce the cost of expensive upgrades from the GIP. Although a state that is developing a project to serve customers *solely* in their state jurisdiction can determine how those costs are shared across customers in their state jurisdiction, the same cannot be said for projects that span two state jurisdictions. It is possible for states to enter into agreements to develop any number of generation and transmission projects, but the issue of who benefits and who pays can create disagreements.

Although the GIP process differs from one RTO or ISO to another, the cost burden of connecting offshore wind through this process rests on the generator, with different reimbursement policies by region. Without a critical mass of offshore wind projects to justify a coordinated offshore grid, it is likely that the first offshore wind projects will be integrated using GIP procedures and radial transmission lines.

In parts of the country with a RTOs or ISOs, states have cooperatively joined together based on the belief that planning generation and transmission across multiple state jurisdictions both fosters competitive markets and results in benefits for all states involved.

Merchant Transmission

Merchant transmission development is a relatively new business model that became viable with FERC's open access laws in the late 1990s. Merchant projects are developed by non-incumbent utilities that are not the owners of the local electric grid and, therefore, do not have captive customers for whom they are required to serve. Merchant transmission projects are not developed with specific rate-paying customers who are obligated to pay for the project; rather, merchant projects are developed with the risk that a market will develop for transmission capacity when they are operational and that the customers will change. These projects require the developer to foster or create a customer base willing to enter into a long-term contract. Merchant transmission projects have *not* been developed in the United States because of the high risk associated with these projects.

A variation of a merchant transmission development that has been built in the United States is called a participant-funded or subscription-based project. Under this merchant structure, a non-incumbent utility without captive customers develops a transmission project to serve a particular generation resource that is seeking transmission services. In contrast to a purely merchant transmission project, a generator must commit to a multiyear PPA for the generation resource (coal, gas, wind, solar, etc.). Like the merchant model, the subscription model is not supported by captive customers; rather, it is supported by the demand for a particular resource in a given market. Examples of merchant transmission projects include Path 15, NEPTUNE, Cross Sound Cable, and Trans Bay Cable. Each of these transmission projects are regulated directly by FERC and developed by non-incumbent utilities. Merchant transmission projects are capital intensive, financially risky, and usually command appropriate incentives to ensure that investors are rewarded for their risk-adjusted return.

Offshore wind will have a difficult time relying on the merchant transmission model for the interconnection of these resources for a number of reasons. First, the wind and transmission siting and permitting processes are independent of one another, which increases the risk for project development. If an offshore wind developer is to rely on the offshore wind transmission interconnection, the permitting and site control for the transmission must occur years in advance. Second, merchant transmission development requires significant development investment before the viability of a project will be ascertained. Although FERC policy allows for certain rate incentives to encourage non-incumbent transmission investment, investors must be willing to put significant development dollars at risk. Third, despite considerable offshore wind development, there are still significant questions about the cost of offshore wind energy.

In 2010, a consortium of investors announced the Atlantic Wind Connection (AWC) offshore wind transmission backbone to serve the offshore wind industry. As proposed in 2010, the AWC is an alternative to developing multiple radial interconnections to meet the growing demand for offshore wind on the Atlantic Coast. The AWC would be built in three phases to serve the growing offshore wind industry. Trans-Elect and Atlantic Grid Development estimated the cost of the AWC to be $5 billion, plus financing and permitting costs. The first phase was identified as the New Jersey Energy Link, a 150-mi stretch from northern New Jersey to Rehoboth Beach, Delaware, to be in service by 2016. Despite bringing in additional investors such as Google, Bregal Energy, Marubeni Corporation, and Elia, the AWC is not scheduled to be in service before 2021.

In 2014, the Atlantic Grid Connection announced that the AWC would continue to be developed as a merchant transmission project without offshore wind development. The New Jersey Energy Link is moving forward on the basis of being able to provide electrical and economic benefits to the New Jersey electric grid. Although AWC continues to provide the option for an efficient interconnection method for offshore wind, the project developers will continue to develop the project solely on the economic and electrical benefits that the transmission project will deliver.

Regional Transmission Planning

As discussed above, federal policy created six RTOs to leverage the relative economic benefits of generation plants and transmission assets that were originally planned and developed by utilities residing in one state. Through an ISO, the RTO system allows market forces to determine what generation is the most economically efficient generation to be dispatched throughout a given market period. States with market participants that participate in RTOs accordingly have the opportunity to identify a broad range of transmission alternatives and select the most efficient transmission plan to meet the policy objectives of the states and the regions.

7.4 Commercialization of Offshore Wind

Approximately 5 GW of offshore could comprise the first generation of operational offshore wind in the United States. The first generation of offshore wind deployment will offer lessons learned that will help inform the extent to which regulatory and permitting of offshore wind may be improved. The central challenge is whether the benefits of offshore wind will outweigh the high cost of offshore wind energy and development. Improvements to the regulatory process—including site control, environmental permitting, and interconnection process—can be made to ensure that the development timeline is efficient, cost-effective, and thorough with respect to our federal, state, and local environmental laws. For offshore wind to achieve deployment on a gigawatt scale, the development timeline must be reduced, and ultimately the LCOE must be reduced so that it is cost competitive with other resources.

Federal Policy Developments

The federal government plays a significant role in regulating and permitting offshore wind, but it also plays a role in helping to encourage the innovation of emerging technologies. Each year, DOE receives a multibillion dollar appropriation to perform multiple duties. Congress also appropriates funding for DOE's research and development programs to help ensure that our nation becomes more energy independent. DOE's research and development programs support every source of energy, from advanced technology fossil-fuel development for coal and natural gas to zero-carbon resources such as nuclear, wind, solar, and hydroelectric power. DOE's Wind Program is currently investing $50 million in research and development to reduce the cost of offshore wind and to reduce the development timeline for deployment. DOE's OSWind Initiative is the first comprehensive research and development program to identify offshore wind as a strategic resource.

In addition to appropriating funds for research and development, through the tax code Congress influences policy that shapes energy development. More than 85 provisions in the tax code affect energy development. It is cliché to say that the United States does not have a formal national energy policy per se. In reality, tax provisions provide incentives for private investment in the exploration and development of a range of energy resources. Despite having robust discussions around federal energy policy, the last major substantive energy legislation was passed in 2005. In the interim, Congress has considered numerous forms of energy legislation that would help form the basis for a national energy policy—from climate change to cap and trade legislation, clean energy standards, a federal renewable energy portfolio standard, to extending certain provisions for production tax credits and other incentives—but nothing has passed. Instead of creating national energy policy by Congress, discrete bills occasionally become law that help incrementally support investments in energy—most notably in passing an extension of previously passed tax credits and other incentives.

Congress's ability to extend certain tax credits plays a significant role in whether these resources continue to be developed.

State Policy Developments

States that have been successful to date in pursuing offshore wind development have done so by passing state laws that support investment in offshore wind. By recognizing the economic development, environmental, and electrical benefits of offshore wind, states have passed laws that encourage investment in this potential resource.

State regulatory bodies regulate the development of electric and gas generation and distribution infrastructure to meet the needs of its residents. Throughout the United States, PUCs oversee the development of the generation and distribution network under a mandate that usually includes three public policy drivers: reliable, affordable, and safe electricity. Although states plan and regulate electric generation, distribution, and transmission in different ways, each of them are responsible for planning to meet the policy goals of their state. In nearly all states, the PUC oversees the development of an integrated resource planning process that determines the mix of generation, distribution, and transmission needed to meet the electrical needs of a state. It is through this process that electric infrastructure is approved based on state-specific policies and principles that usually assess the overall cost of the project and the anticipated benefit. Through IRP planning, utilities and independent power producers put forth proposals for serving customers.

State legislatures have always responded to economic, environmental, and public health concerns by adjusting which of these factors receives a greater emphasis at any given point in time. Historically, states have enacted policies that require the electricity in the state to be developed from certain resources that may benefit the economic, environmental, and/or public health of its citizens. Across different regions in the country, preferences for coal, nuclear, gas, wind, solar, and geothermal are expressed based on the relative cost of developing those resources and the abundance of the resource.

The establishment of RPS laws in 29 states plus the District of Columbia has been a major impetus for utilities' procurement of electricity from land-based wind and solar. During the past four years, the cost of wind has declined 43% and the installed cost of solar has declined more than 66%. Different policies can promote offshore wind. An offshore wind carve-out (e.g., New Jersey and Maryland) mandates a certain amount of capacity or electricity throughout a certain time from offshore wind resources. In New Jersey, the Board of Public Utilities has the ability to set the cost for an OREC to provide the minimum price structure to support a given project that is seeking approval. In Maryland, cost concerns were addressed by limiting the procurement of offshore wind to 200 MW and broadening the definition of benefits to include employment, taxes, health and environmental benefits, supply chain opportunities, rate payer impacts, and the long-term effect on energy and capacity markets. Broadening the definition of what a PUC may consider in approving an offshore wind contract has also been enacted in Maine, Massachusetts, Rhode Island, New Jersey, and Maryland.

Since 1990, state legislatures have enacted RPS laws in 29 states plus the adoption of voluntary goals in an additional 8 states. The support for renewable energy goals or mandates reached nearly 75% of the United States and resulted in renewable energy generation contributing more than 44% of the *new* electricity generated from all sources in the United States in 2013 [36].

Table 7-3 provides a list of proposed commercial offshore wind projects that have been announced and have initiated steps toward development of the project. This information is based on the best available public information, developer statements and media coverage and may change.

Table 7-3. Proposed Commercial Offshore Wind Projects by State

State	Capacity	Description
Delaware **NRG Bluewater Mid-Atlantic Wind Park**	450 MW	NRG Bluewater's Mid-Atlantic Wind Park received a PPA for 200 MW of power and one of the first offshore wind leases from BOEM in 2010. Delmarva Power canceled the PPA for 200 MW of power. The project is currently on hold. Target completion date is post-2020.
Maine **Statoil North America**	12 MW	Statoil planned to deploy four 3-MW wind turbines on floating spar buoy structures offshore Boothbay Harbor at a water depth of 460 feet. By utilizing local assembly and towing the turbines to the deep waters off the coast of Maine, the project would have demonstrated floating technology in deep water and an installation methodology that could reduce costs. Statoil announced the cancellation of the project in October 2013.
University of Maine Aqua Ventus	12 MW	DeepCwind Consortium plans to install a pilot floating offshore wind farm with two 6-MW direct-drive turbines on semisubmersible foundations near Monhegan Island. This could help establish a cost-effective alternative to traditional steel foundations through design and local assembly.
Massachusetts **Cape Wind**	468 MW	Energy Management, Inc., is developing Cape Wind (MW) in Nantucket Sound approximately 6 mi offshore of Cape Cod in federal jurisdictional waters. Cape Wind expects to complete financing in the second half of 2014 and begin construction in 2015. The commercial operation date is 2016. Cape Wind has a PPA with National Grid and NSTAR for 363 MW or 77.5% of output at a price of $187/MWh.
New York **Deepwater One Regional Energy Center**	900–1,200 MW	Deepwater One is a regional energy center designed to serve Long Island and ISO-NE. It is in the early stages of development. The target completion date is 2019.
Hudson Canyon Wind Farm	1,000 MW	Deepwater describes the Hudson Canyon Wind Farm as a second-generation offshore wind project to be built 35 mi off the western end of Long Island with the ability to serve customers in New York and New Jersey. The target completion date is post 2020.
New Jersey **Fisherman's Energy Atlantic City Wind Farm**	25 MW	Fishermen's Energy plans to install up to six direct-drive turbines in state waters 2.8 mi from Atlantic City, New Jersey, which offers innovative bottom-mounted foundation design and environmentally-friendly installation procedures. The target operation date is 2016.
Garden State Offshore Energy	1,000 MW	Garden State Offshore Energy is jointly developed by Deepwater Wind and PSE&G Renewable Generation, LLC. It is in the early stages of development. The target completion date is 2019.
Ohio **Lake Erie Development Corporation Icebreaker**	27 MW	LEEDCo plans to install nine 3-megawatt direct-drive wind turbines on "ice breaker" monopole foundations designed to reduce ice loading. The project is based on Lake Erie 7 mi off the coast of Cleveland.
Rhode Island **Block Island Wind Farm**	30 MW	Deepwater Wind is developing the Block Island Wind Farm, a five-turbine offshore wind project approximately 3 mi southeast of Block Island in Rhode Island state waters. Construction begins in 2015.

Cont. below …

Table 7-3. Proposed Commercial Offshore Wind Projects by State, Cont.

State	Capacity	Description
Texas **Baryonyx Rio Grande Wind Farms**	1,000 MW	Baryonyx Corp. secured leases from the Texas General Land Office in 2009 for the development of the Rio Grande North and South projects approximately 10 mi from shore and 5 mi from South Padre Island in Texas state waters. The U.S. Army Corps of Engineer environmental permitting is underway. The target completion date is 2019.
Coastal Point Energy Galveston Offshore Wind	150 MW	Coastal Point Energy (formerly Wind Energy Systems Technology) secured lease from the Texas General Land Office. They have deployed a met tower in the Gulf of Mexico and announced the intention to install a 750-kW test turbine.
Virginia **Dominion Virginia Power Virginia Offshore Wind Technology Assessment Program (VOWTAP)**	12 MW	Dominion plans to design, develop, and install two 6-MW direct-drive turbines off the coast of Virginia Beach on innovative “twisted jacket” foundations. This projects offers the potential for significant cost reductions compared to traditional jacket foundations by using substantially less steel.
U.S. Total	**5,386 MW**	Note: Total capacity includes several projects that are on hold or have been cancelled, but it represents the total possible capacity before 2020.

7.5 Policy Recommendations

To interconnect 54 GW of offshore wind resources, a comprehensive, dual-track federal and state strategy is needed to align state, federal, and other stakeholder interests. DOE has developed a roadmap for the development of gigawatt-scale offshore wind resources in the United States. To realize this vision, both federal and state policies are required to help reduce development timelines and reduce costs for offshore wind. As the first generation of offshore wind projects are deployed, state and federal policies that promote offshore wind projects should be evaluated. Federal permitting by BOEM is still untested, but the improvements in site control and permitting are improvements from a dozen years ago.

At the federal level, DOE research and development should continue to evaluate the best way to reduce the installed LCOE for offshore wind. DOE’s advanced technology demonstration projects will deploy three offshore wind projects that will help to demonstrate the electrical potential of offshore wind. These projects will be among the first to pursue the regulatory pathway for offshore wind—siting, environmental permitting, power contract, and interconnecting to the electric grid. Although these projects face a streamlined BOEM siting and improved environmental permitting regime on the OCS, lessons learned will emerge as each region learns about the potential benefits and costs of offshore wind development. In addition to the three demonstration projects selected in May 2014, four projects are candidates to demonstrate how the deployment of offshore wind can be achieved at a reduced cost and timeline. As the first demonstration and commercial projects are deployed, the environmental impacts may be better understood through data collection. Likewise, regulators will have the opportunity to streamline the NEPA permitting process so that concurrent environmental reviews can be conducted with data from other regions, which will help projects avoid and mitigate any potential impacts to important historic, cultural, and environmental resources.

Research and development into reducing the LCOE should also continue until the offshore wind industry is mature. Nearly all energy sources receive federal and state subsidies for exploration and development. Although some of these provisions in the tax code are permanent, others require approval based on Congress. For wind and solar, investment tax credits and production tax credits have provided important financial incentives to the installation of emerging technologies. The ebb and flow of wind development follows very closely with the support of tax credits throughout the past decade. Similar policy decisions for offshore wind are likely to influence offshore wind development, particularly with the immature state of the industry and the high capital costs associated with offshore installations. The level of public desire for offshore wind and the cost in the overall energy budget will need to be weighed in such political decisions. Congress should explore the inclusion of offshore wind in the investment tax credit extension that is set to expire at the end of 2014. Enacting tax credit supports that will extend through 2020 will help support the first generation of offshore wind projects.

RPSs now exist in 75% of the United States and represent a model for state self-determination with regard to energy, economic, and environmental goals. States must determine whether the benefits of offshore wind are worth the investment in infrastructure and the potentially higher cost of electricity that may come with the first generation or projects. States control their ability to lease and grant site control for projects. Likewise, states can determine that offshore wind is an economic development opportunity for attracting a new industry and new jobs in areas that need opportunity the most. States also control where their energy development priorities rest—taking into account the policy trade-offs of building transmission to deliver wind from the Midwest and western part of the country to load centers on the coasts. Although certain regions of the country are endowed with certain energy resources, it is the states that must determine the most cost-effective way to promote and develop their resources—making value judgments about land use, aesthetics, energy security, as well as environmental health and public health. It is states that will pass legislation to encourage offshore wind development because of the opportunity to create jobs, reduce greenhouse gas emissions, and deliver the electrical benefits of offshore wind—projected by this report to be $41/MWh.

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8.0 CONCLUSIONS

NOWEGIS is one piece of a body of work funded by DOE under funding opportunity announcement DE-FOA-0000414, which was designed to identify and help address market barriers to the large-scale introduction of offshore wind energy into the U.S. energy portfolio. NOWEGIS was a national-level study (lower 48 states) that considered the resources, technologies, and regulatory environment that may advance or hinder this goal. The key results expected to be of primary interest to executives and decision makers are discussed below, with additional supporting descriptions of the work in the balance of the executive summary and in the main report.

8.1 Key Results and Observations

1. **The United States has sufficient offshore wind energy resources to consider having at least 54 GW of offshore wind.** NOWEGIS focused on the ability to integrate up to 54 GW of offshore wind into the U.S. grid by 2030 based on the levels proposed in the DOE report *20% Wind Energy by 2030* [1]. However, the resource assessment—which considered exclusion zones required because of military use, commercial shipping lanes, environmental concerns, and sites that were not ultimately selected—indicates that a significantly larger amount of offshore wind could, in theory, be utilized.

2. **The methods used for evaluating the integration of land-based wind energy are also appropriate for studying offshore wind energy.** The methods currently used for onshore wind power plants to evaluate system impacts, determine generation reserve requirements, estimate system-wide operational costs, etc., apply directly to studying offshore wind. The same types of data—including wind production profiles in the hourly and intra-hourly time frames, system topology, and rating information—are required.

3. **Appropriate technologies exist for the interconnection of large amounts of wind energy to the U.S. grid.** Multiple technologies exist that can be used to collect the wind-generated electricity and deliver it to the onshore grid. Those that are designed for AC have distance limitations that require them to be near shore or have additional offshore equipment to allow for farther distances. Those technologies that are designed for DC are generally more expensive because of the need for larger converter systems, but when configured in an offshore backbone or grid show the potential to bring important benefits to the onshore grid that may help justify their higher costs.

4. **At a regional or national level, offshore wind energy may provide significant value.** Although offshore wind projects are likely to have high capital costs, there are some benefits that accrue from a system-wide perspective that can help to justify the high initial investment. For example, NOWEGIS estimated that the 54 GW of offshore wind provided a national reduction of annual production costs of $7.68 billion, resulting in a value of offshore wind of approximate $41/MWh.

5. **State policies that recognize the energy, environmental, and economic benefits of offshore wind are critical to encourage investment in offshore wind.** Because of the higher capital costs, potential grid reinforcement requirements, and, to some degree, the uncertainties associated with first deployments of commercial-scale offshore wind projects, state policies are required to purchase power from offshore wind projects. State policies can encourage offshore wind deployment by creating demand for this resource through RPSs that establish policy mechanisms based on the needs of the state—carve-outs, minimum requirements, or even aspirational goals. Some states have altered the regulatory paradigm to allow for the inclusion of

a broader range of benefits—including economic development, environmental benefits (carbon-free power), and energy benefits of offshore wind. State policies are needed to recognize the energy, environmental, and economic benefits and to create demand for offshore wind.

6. **Reductions in the federal permitting and siting process are critical for offshore wind deployment to achieve gigawatt-scale in the next decade.** *Although great strides have been made to reduce the permitting schedule from 12 yr for Cape Wind to between 2 yr and 4 yr, further enhancements by the multitude of federal permitting and regulatory agencies are needed.* Further, if offshore delivery networks interconnect multiple entities (utilities, ISOs, RTOs), significant cooperation will be required to ensure the equitable distribution of cost burdens and benefits. This may require oversight at the federal level, but it is currently unclear what form of oversight might work best.

7. **Current organizational structures in the United States may make it more difficult to attain the offshore wind value found in the study.** This is because the value levels indicated above rely on a regional (or broader) perspective. Areas such as the southeast United States that do not have RTOs may find it difficult to socialize the costs and benefits sufficiently to justify the costs. Even large utilities such as Duke Energy may have difficulty doing so. On the other hand, working from such a perspective may be more straightforward in areas with an ISO or RTO (e.g., ISO-ISO-NE or PJM), but even here each state and utility involved must be willing to consider and share in the broader perspective, costs, and benefits.

8. **Research and development promise to help reduce initial capital investment.** One of the major market barriers to offshore wind is and will continue to be the high capital costs compared to other forms of energy production. However, several areas of research and development are available that can help reduce those initial costs. These include cable developments, offshore platform innovations, and platform size and weight reductions accomplished through companion development of wind turbine configurations and collector system design as well as compact HVDC converter development. Many of these developments may be pursued by the industry, but governmental and academic cooperative agreements with the industrial manufacturers will help to commercialize any developments more rapidly and in a manner consistent with actual market demands.

APPENDIX A—TABLE OF SELECTED SITES FROM WIND PRODUCTION PROFILE DEVELOPMENT

Table A-1. Table of Selected Sites from Wind Production Profile Development

SITE	CAP (MW)	LAT	LON	MEAN DEPTH (M)	COAST DIST (KM)	WSPD 100M (M/S)	REEDS ZONE	REGION	STATE	EST COE ($/MWH)	54 GW
1	699	32.47	-79.79	-17	24	8.0	299	Atlantic	SC	206.0	x
2	390	36.02	-74.74	-785	75	8.9	294	Atlantic	NC	220.0	
3	1477	35.42	-75.30	-26	17	8.6	294	Atlantic	NC	189.1	x
5	554	35.05	-75.30	-119	28	8.8	294	Atlantic	NC	218.1	x
6	360	36.65	-75.05	-29	74	8.8	294	Atlantic	NC	189.0	x
7	1807	40.66	-72.32	-44	24	9.2	342	Atlantic	NY	207.7	x
8	1178	40.21	-72.52	-58	65	9.3	342	Atlantic	NY	207.3	x
9	593	42.59	-69.56	-261	74	9.7	349	Atlantic	MA	199.3	x
10	642	42.29	-69.26	-219	70	9.8	349	Atlantic	MA	198.2	x
11	749	40.99	-69.43	-32	78	9.7	349	Atlantic	MA	200.0	
12	936	33.45	-78.65	-18	34	8.3	298	Atlantic	SC	199.5	x
13	988	32.93	-79.15	-17	24	8.4	298	Atlantic	SC	197.1	x
14	694	33.11	-78.68	-22	47	8.5	298	Atlantic	SC	194.0	x
15	1920	38.20	-74.31	-45	69	8.5	315	Atlantic	MD	227.3	x
16	1398	40.29	-71.92	-68	75	9.4	342	Atlantic	NY	206.1	x
17	867	40.01	-73.00	-51	72	9.3	342	Atlantic	NY	208.0	x
18	2083	40.68	-71.84	-56	39	9.4	342	Atlantic	NY	203.8	x
19	428	40.67	-71.31	-61	64	9.4	342	Atlantic	NY	204.3	x
20	1098	41.01	-69.90	-22	61	9.6	349	Atlantic	MA	171.5	x
21	553	41.54	-69.74	-25	21	9.5	349	Atlantic	MA	171.2	x
22	963	31.23	-80.54	-28	68	8.0	275	Atlantic	GA	212.0	x
23	957	30.85	-80.95	-20	44	7.5	275	Atlantic	GA	225.9	
24	643	30.57	-81.07	-22	34	7.2	310	Atlantic	FL	240.6	x
26	1896	39.48	-73.49	-36	60	9.1	330	Atlantic	NJ	211.0	x
27	1352	38.07	-74.96	-21	20	8.3	315	Atlantic	MD	196.8	x
28	544	37.98	-74.69	-34	46	8.4	315	Atlantic	MD	228.8	x
29	861	32.11	-79.67	-33	64	8.2	299	Atlantic	SC	241.1	x
30	1015	37.73	-75.16	-24	23	8.3	314	Atlantic	VA	196.8	
31	977	37.72	-75.38	-15	15	8.2	314	Atlantic	VA	201.6	
32	854	37.60	-75.35	-20	24	8.3	314	Atlantic	VA	197.3	
33	878	37.58	-74.78	-46	60	8.6	314	Atlantic	VA	225.9	
34	1007	37.26	-75.11	-31	59	8.6	314	Atlantic	VA	225.3	
35	901	37.25	-74.92	-42	74	8.7	314	Atlantic	VA	225.6	
36	887	37.58	-74.89	-35	52	8.6	314	Atlantic	VA	226.0	
37	1005	37.47	-75.33	-26	31	8.4	314	Atlantic	VA	194.7	x
38	453	39.04	-75.22	-10	10	8.1	318	Atlantic	DE	202.6	x
39	562	42.81	-70.09	-125	44	9.4	348	Atlantic	MA	202.6	x

SITE	CAP (MW)	LAT	LON	MEAN DEPTH (M)	COAST DIST (KM)	WSPD 100M (M/S)	REEDS ZONE	REGION	STATE	EST COE ($/MWH)	54 GW
40	891	43.66	-69.10	-109	20	9.6	356	Atlantic	ME	197.2	
41	564	38.04	-74.34	-52	72	8.5	315	Atlantic	MD	229.6	x
42	537	37.87	-74.41	-60	72	8.6	315	Atlantic	MD	227.1	x
43	851	39.95	-73.95	-20	10	8.6	330	Atlantic	NJ	186.2	x
44	1153	39.07	-73.73	-41	66	8.9	330	Atlantic	NJ	216.7	x
45	1099	39.78	-73.48	-36	52	9.1	330	Atlantic	NJ	209.0	x
46	380	41.18	-72.80	-19	7	7.7	344	Atlantic	CT	213.9	x
47	1009	34.15	-77.60	-18	18	8.1	293	Atlantic	NC	204.6	x
48	1014	34.25	-77.14	-25	36	8.4	293	Atlantic	NC	195.6	x
49	570	33.84	-77.20	-33	67	8.5	293	Atlantic	NC	229.0	x
50	571	37.68	-74.57	-58	71	8.6	314	Atlantic	VA	226.1	
51	416	41.22	-71.73	-34	12	8.4	345	Atlantic	RI	226.4	x
52	817	40.49	-73.78	-20	11	8.4	341	Atlantic	NY	194.9	x
53	25	39.28	-74.43	-14	8	8.4	332	Atlantic	NJ	194.5	
54	1134	34.15	-76.54	-35	48	8.6	294	Atlantic	NC	225.6	
55	30	41.12	-71.52	-26	27	9.2	345	Atlantic	RI	176.2	x
56	328	41.50	-70.32	-9	13	8.9	349	Atlantic	MA	183.3	x
57	158	43.52	-69.53	-146	31	9.4	356	Atlantic	ME	201.8	
58	499	41.00	-71.22	-43	46	9.3	345	Atlantic	RI	204.4	x
59	903	40.30	-73.32	-34	36	9.1	342	Atlantic	NY	209.9	x
60	1862	39.38	-74.03	-25	26	8.7	330	Atlantic	NJ	185.9	x
61	468	38.59	-74.68	-23	33	8.4	315	Atlantic	MD	194.2	x
62	888	38.35	-74.76	-25	27	8.4	315	Atlantic	MD	194.2	x
63	951	36.89	-75.35	-28	55	8.6	307	Atlantic	VA	192.8	x
64	1015	36.35	-75.53	-23	24	8.5	294	Atlantic	NC	193.0	x
65	951	36.34	-75.11	-35	60	8.8	294	Atlantic	NC	221.1	
66	812	36.03	-75.38	-27	23	8.5	294	Atlantic	NC	193.6	x
67	1023	33.50	-77.95	-25	38	8.4	292	Atlantic	NC	197.0	x
68	408	33.71	-78.26	-16	22	8.1	292	Atlantic	NC	204.9	
69	567	39.00	-74.39	-26	29	8.6	332	Atlantic	NJ	189.9	x
70	887	40.69	-70.55	-58	86	9.5	349	Atlantic	MA	204.8	
71	887	41.05	-70.53	-43	50	9.4	349	Atlantic	MA	203.2	
72	317	41.05	-73.29	-21	7	7.8	344	Atlantic	CT	210.8	x
73	351	42.98	-70.68	-29	5	8.3	354	Atlantic	NH	193.2	x
74	951	32.01	-80.28	-22	31	8.0	297	Atlantic	SC	207.9	
144	436	43.60	-67.96	-214	63	10.0	356	Atlantic	ME	192.6	x
145	652	43.07	-69.71	-126	66	9.6	356	Atlantic	ME	200.1	
146	302	44.10	-68.13	-78	10	9.4	356	Atlantic	ME	199.9	
147	466	44.33	-67.60	-85	13	9.4	356	Atlantic	ME	200.3	
148	600	33.79	-77.69	-22	25	8.3	292	Atlantic	NC	197.4	

SITE	CAP (MW)	LAT	LON	MEAN DEPTH (M)	COAST DIST (KM)	WSPD 100M (M/S)	REEDS ZONE	REGION	STATE	EST COE ($/MWH)	54 GW
149	545	41.21	-69.08	-115	84	9.7	349	Atlantic	MA	199.9	x
150	911	35.02	-75.76	-24	17	8.6	294	Atlantic	NC	191.4	x
151	522	30.10	-81.20	-16	14	6.9	310	Atlantic	FL	255.0	
152	919	31.56	-80.34	-30	67	8.0	297	Atlantic	SC	246.9	
1000	469	29.53	-89.45	0	10	7.0	261	Gulf	LA	250.9	
1001	301	30.35	-87.95	-3	8	7.2	267	Gulf	AL	244.4	
1004	645	30.05	-88.98	-5	36	7.2	264	Gulf	MS	243.8	
1005	301	29.42	-91.66	-2	12	7.5	261	Gulf	LA	226.2	
1006	682	28.75	-94.63	-24	58	7.9	175	Gulf	TX	215.5	
1007	763	27.66	-96.40	-69	63	8.5	174	Gulf	TX	230.0	
1008	1015	27.22	-97.10	-30	25	8.8	174	Gulf	TX	185.5	
1009	557	28.04	-96.13	-38	42	8.3	174	Gulf	TX	238.2	
1010	423	28.46	-95.87	-19	18	8.1	174	Gulf	TX	204.8	
1011	301	29.01	-95.02	-15	12	7.8	175	Gulf	TX	217.4	
1012	301	27.98	-96.77	-17	13	8.3	174	Gulf	TX	197.7	
1013	804	26.82	-97.12	-31	23	9.0	174	Gulf	TX	213.6	
1014	389	27.37	-96.75	-57	53	8.8	174	Gulf	TX	219.7	
1015	605	28.26	-95.33	-41	63	8.0	174	Gulf	TX	250.4	
1016	502	28.78	-94.28	-26	75	7.8	175	Gulf	TX	219.6	
1017	686	29.15	-92.71	-21	49	7.6	162	Gulf	LA	226.0	
1018	456	29.05	-92.10	-17	54	7.6	261	Gulf	LA	226.5	
1019	391	28.74	-90.43	-19	35	7.4	261	Gulf	LA	233.0	
1024	330	29.93	-88.61	-22	44	7.3	264	Gulf	MS	240.9	
1025	365	30.07	-87.71	-20	20	7.2	267	Gulf	AL	242.0	
1028	1026	26.31	-96.71	-45	48	8.5	174	Gulf	TX	228.3	
1029	328	29.46	-94.08	-12	21	7.6	256	Gulf	TX	223.1	x
1030	309	29.18	-94.74	-15	12	7.8	175	Gulf	TX	216.5	
1031	1017	26.30	-97.09	-19	11	8.8	174	Gulf	TX	185.3	
2002	933	29.16	-80.70	-23	23	7.0	311	Florida	FL	252.2	x
2003	951	28.69	-80.41	-19	20	7.0	313	Florida	FL	250.6	
2016	546	28.26	-80.44	-18	16	7.0	313	Florida	FL	250.6	
2020	460	23.88	-81.77	0	73	7.5	312	Florida	FL	234.2	
2025	559	29.43	-85.03	-18	18	6.9	309	Florida	FL	257.5	
2026	507	29.70	-85.54	-22	15	6.9	270	Florida	FL	258.5	x
2027	438	30.19	-86.95	-30	19	7.2	269	Florida	FL	245.8	x
2037	741	29.50	-84.44	-22	36	7.0	309	Florida	FL	255.4	
2058	543	23.95	-82.42	0	90	7.3	312	Florida	FL	245.0	
4000	302	45.69	-84.06	-53	13	8.1	216	Lakes	MI	235.6	
4001	297	45.63	-85.98	-32	33	8.9	211	Lakes	MI	217.5	x
4002	302	42.20	-87.55	-42	17	8.7	206	Lakes	IL	219.4	

SITE	CAP (MW)	LAT	LON	MEAN DEPTH (M)	COAST DIST (KM)	WSPD 100M (M/S)	REEDS ZONE	REGION	STATE	EST COE ($/MWH)	54 GW
4003	296	47.10	-89.01	-45	8	8.4	191	Lakes	MI	227.8	
4004	302	47.01	-88.05	-46	8	8.3	191	Lakes	MI	228.1	
4005	308	42.91	-86.31	-44	8	8.6	212	Lakes	MI	225.4	
4006	298	43.84	-76.54	-43	9	8.3	336	Lakes	NY	232.0	
4007	295	46.90	-85.10	-40	16	8.2	211	Lakes	MI	231.5	
4008	302	46.68	-90.53	-28	9	7.3	129	Lakes	WI	225.9	
4009	302	47.08	-90.84	-38	13	7.5	129	Lakes	WI	257.9	
4010	363	47.36	-87.42	-160	23	9.3	191	Lakes	MI	203.1	
4011	321	44.27	-86.86	-220	36	9.0	212	Lakes	MI	212.1	x
4012	302	43.98	-87.17	-104	36	8.9	197	Lakes	WI	212.5	
4013	302	43.09	-86.75	-104	36	9.0	212	Lakes	MI	213.8	
4014	302	42.80	-87.15	-146	49	8.7	198	Lakes	WI	218.6	
4015	319	43.46	-86.68	-108	18	8.9	212	Lakes	MI	215.2	
4016	328	43.58	-77.86	-171	25	8.4	334	Lakes	NY	227.6	
4017	743	43.51	-87.53	-135	21	8.6	198	Lakes	WI	220.7	
4018	298	48.09	-88.95	-183	42	8.1	191	Lakes	MI	239.2	
4019	491	47.41	-90.06	-145	42	7.8	125	Lakes	MN	248.6	
4022	302	45.34	-82.86	-128	41	8.9	216	Lakes	MI	213.2	x
4023	518	45.54	-83.21	-106	30	8.6	216	Lakes	MI	219.3	
4024	311	47.33	-86.57	-247	80	9.6	191	Lakes	MI	200.7	
4025	367	47.30	-86.03	-147	68	9.4	191	Lakes	MI	203.4	
4026	302	47.92	-87.93	-235	48	9.1	191	Lakes	MI	207.9	
4027	368	45.14	-86.19	-120	28	9.0	212	Lakes	MI	213.1	x
4028	593	47.85	-88.30	-251	44	8.9	191	Lakes	MI	213.9	
4029	426	47.43	-88.98	-160	33	8.8	191	Lakes	MI	216.6	
4030	329	44.65	-87.05	-175	24	8.8	197	Lakes	WI	215.2	
4031	601	47.74	-88.82	-217	51	8.5	191	Lakes	MI	224.3	
4032	302	43.59	-77.24	-152	35	8.5	334	Lakes	NY	225.2	
4033	303	47.28	-89.48	-203	42	8.3	191	Lakes	MI	230.2	
4034	733	43.55	-78.56	-164	21	8.4	333	Lakes	NY	229.9	
4035	302	47.34	-90.51	-95	36	7.6	125	Lakes	MN	257.5	
4036	501	47.72	-89.72	-184	19	7.6	125	Lakes	MN	257.5	
4037	350	45.65	-86.46	-45	9	8.7	191	Lakes	MI	222.5	
4038	341	46.64	-84.93	-38	8	7.9	211	Lakes	MI	244.7	
4039	940	41.68	-81.91	-20	20	8.3	234	Lakes	OH	200.3	
4040	595	41.60	-82.11	-16	12	8.3	234	Lakes	OH	199.0	
4041	1504	42.45	-79.76	-40	17	8.3	333	Lakes	NY	234.7	
4042	391	42.19	-80.65	-22	25	8.4	234	Lakes	OH	196.1	
4043	1063	42.26	-80.38	-20	23	8.5	320	Lakes	PA	194.9	
4044	447	42.10	-80.97	-22	25	8.4	234	Lakes	OH	194.9	

SITE	CAP (MW)	LAT	LON	MEAN DEPTH (M)	COAST DIST (KM)	WSPD 100M (M/S)	REEDS ZONE	REGION	STATE	EST COE ($/MWH)	54 GW
4045	636	42.01	-80.98	-21	17	8.4	234	Lakes	OH	195.9	
4046	607	41.72	-83.04	-8	13	8.0	227	Lakes	OH	205.5	
4047	180	46.82	-86.48	-32	28	9.3	191	Lakes	MI	204.4	
4048	898	41.97	-86.72	-34	12	8.1	213	Lakes	MI	239.4	x
4049	798	45.51	-87.14	-24	10	8.2	191	Lakes	MI	199.3	x
4050	489	44.50	-83.07	-40	20	8.1	216	Lakes	MI	237.5	
4051	424	44.15	-83.03	-32	11	8.5	218	Lakes	MI	224.6	
4052	270	44.40	-82.54	-40	46	8.8	218	Lakes	MI	217.5	
4053	117	43.63	-82.45	-40	12	8.1	218	Lakes	MI	235.0	
4054	136	43.45	-82.38	-39	13	8.0	218	Lakes	MI	238.7	
4055	355	43.32	-82.31	-35	18	8.1	218	Lakes	MI	237.4	
4056	813	41.88	-86.93	-37	16	8.1	219	Lakes	IN	238.7	x
4057	307	45.29	-86.66	-55	17	8.8	197	Lakes	WI	215.8	
4058	329	42.50	-86.41	-54	13	8.4	212	Lakes	MI	227.6	
4059	396	45.70	-85.17	-25	11	8.4	214	Lakes	MI	195.9	
5000	691	46.54	-125.04	-1402	75	8.7	1	Pacific	WA	228.6	
5001	823	47.73	-125.37	-912	59	8.7	1	Pacific	WA	228.1	
5002	397	46.01	-124.07	-55	9	8.2	10	Pacific	OR	246.4	
5003	724	43.08	-124.80	-232	29	9.8	14	Pacific	OR	205.3	
5004	760	42.62	-125.17	-2433	55	10.1	14	Pacific	OR	199.6	
5005	562	40.67	-125.08	-2655	61	10.4	20	Pacific	CA	197.5	
5006	604	40.13	-125.23	-1607	74	10.2	20	Pacific	CA	198.2	
5007	571	38.57	-123.91	-2047	37	9.6	20	Pacific	CA	207.0	
5008	739	37.14	-123.16	-1795	65	8.5	25	Pacific	CA	235.0	
5009	518	36.10	-122.48	-2574	56	8.4	29	Pacific	CA	234.1	
5010	518	34.27	-121.39	-2414	75	8.6	29	Pacific	CA	225.6	
5011	760	34.01	-120.97	-1669	48	9.0	29	Pacific	CA	213.9	
5015	374	38.24	-123.74	-2069	51	9.6	25	Pacific	CA	207.1	
5016	743	38.45	-123.35	-105	11	9.0	25	Pacific	CA	216.0	
5017	691	48.07	-125.77	-804	77	9.0	1	Pacific	WA	220.7	x
5018	429	45.96	-124.95	-960	74	8.7	1	Pacific	WA	231.5	
5019	864	47.25	-125.24	-1395	71	8.8	1	Pacific	WA	226.0	
5020	773	45.58	-124.55	-332	46	8.6	10	Pacific	OR	231.8	
5021	724	45.17	-124.50	-384	40	8.8	10	Pacific	OR	226.2	
5022	761	44.81	-124.67	-348	47	9.1	13	Pacific	OR	220.3	
5023	521	44.47	-125.05	-974	76	9.2	13	Pacific	OR	220.1	
5024	965	44.03	-124.86	-161	58	9.3	15	Pacific	OR	216.5	
5025	732	43.55	-125.17	-1499	67	9.4	14	Pacific	OR	213.5	
5026	700	42.54	-124.69	-183	22	10.7	14	Pacific	OR	192.4	x
5027	675	42.00	-125.27	-3024	76	10.6	14	Pacific	OR	195.9	

SITE	CAP (MW)	LAT	LON	MEAN DEPTH (M)	COAST DIST (KM)	WSPD 100M (M/S)	REEDS ZONE	REGION	STATE	EST COE ($/MWH)	54 GW
5028	413	40.09	-124.41	-657	17	10.6	20	Pacific	CA	191.4	x
5029	707	39.88	-124.82	-1382	57	10.3	20	Pacific	CA	195.8	
5030	544	35.93	-121.91	-1239	32	8.7	29	Pacific	CA	218.2	
5031	823	35.63	-122.27	-3187	76	8.6	29	Pacific	CA	225.6	
5033	774	34.63	-121.31	-860	61	8.4	29	Pacific	CA	232.2	
5034	596	34.35	-120.93	-980	36	8.8	29	Pacific	CA	218.7	
5036	570	33.74	-120.44	-1223	31	9.3	29	Pacific	CA	209.0	
5037	950	33.53	-119.71	-529	30	8.1	31	Pacific	CA	243.9	
5041	718	47.02	-124.41	-54	18	8.5	1	Pacific	WA	230.0	
5042	669	46.50	-124.18	-34	10	8.4	1	Pacific	WA	237.9	
5043	570	44.26	-124.22	-59	8	8.6	13	Pacific	OR	230.1	
5045	625	40.61	-124.44	-54	9	8.5	20	Pacific	CA	235.2	

APPENDIX B—ADDITIONAL LOAD AND NET LOAD GRAPHS

B.1 Boxplots Showing Daily Load and Net Load Variability

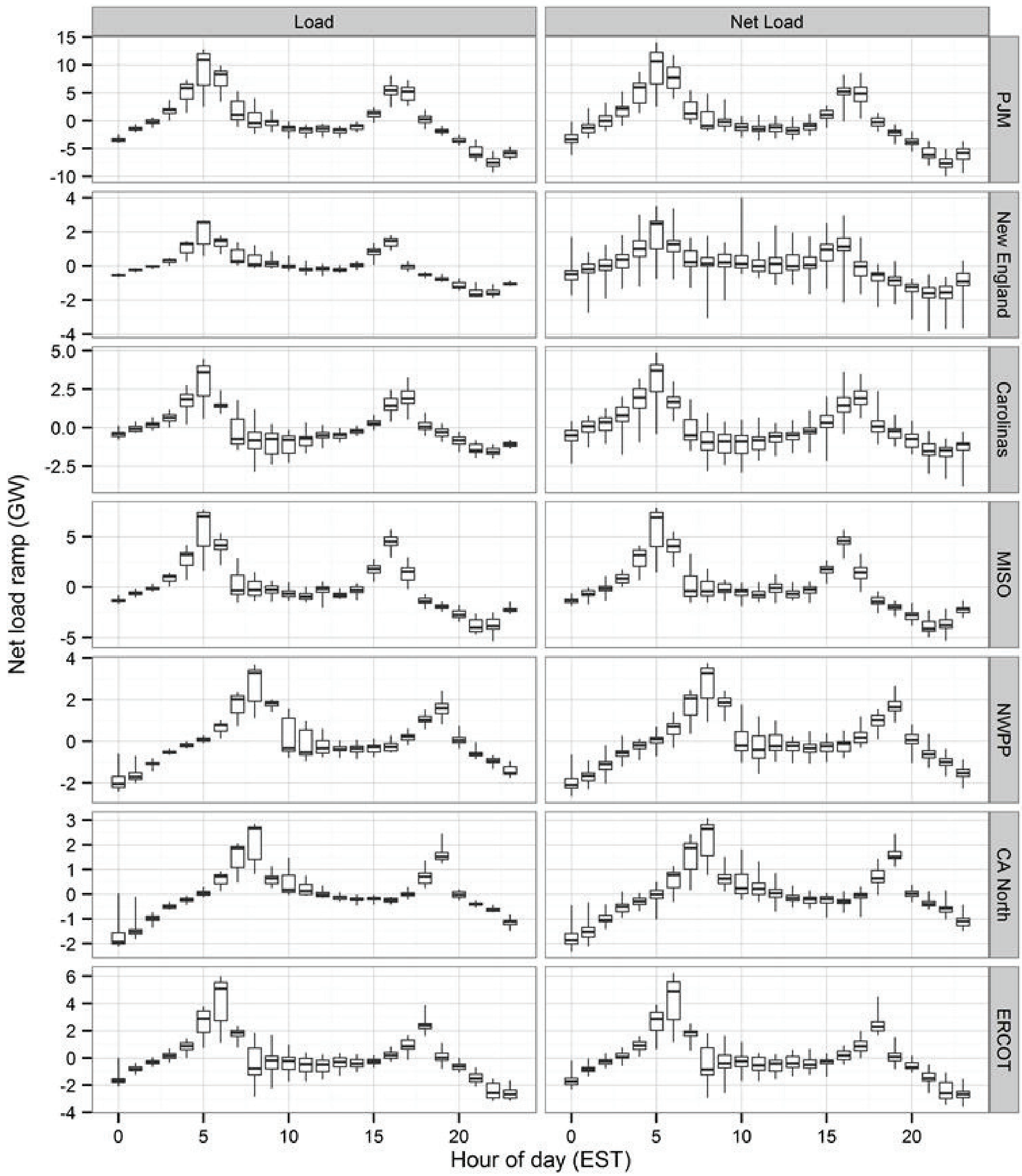

Figure B-1. Boxplots showing load and net load hourly variability by hour of day for January 2006

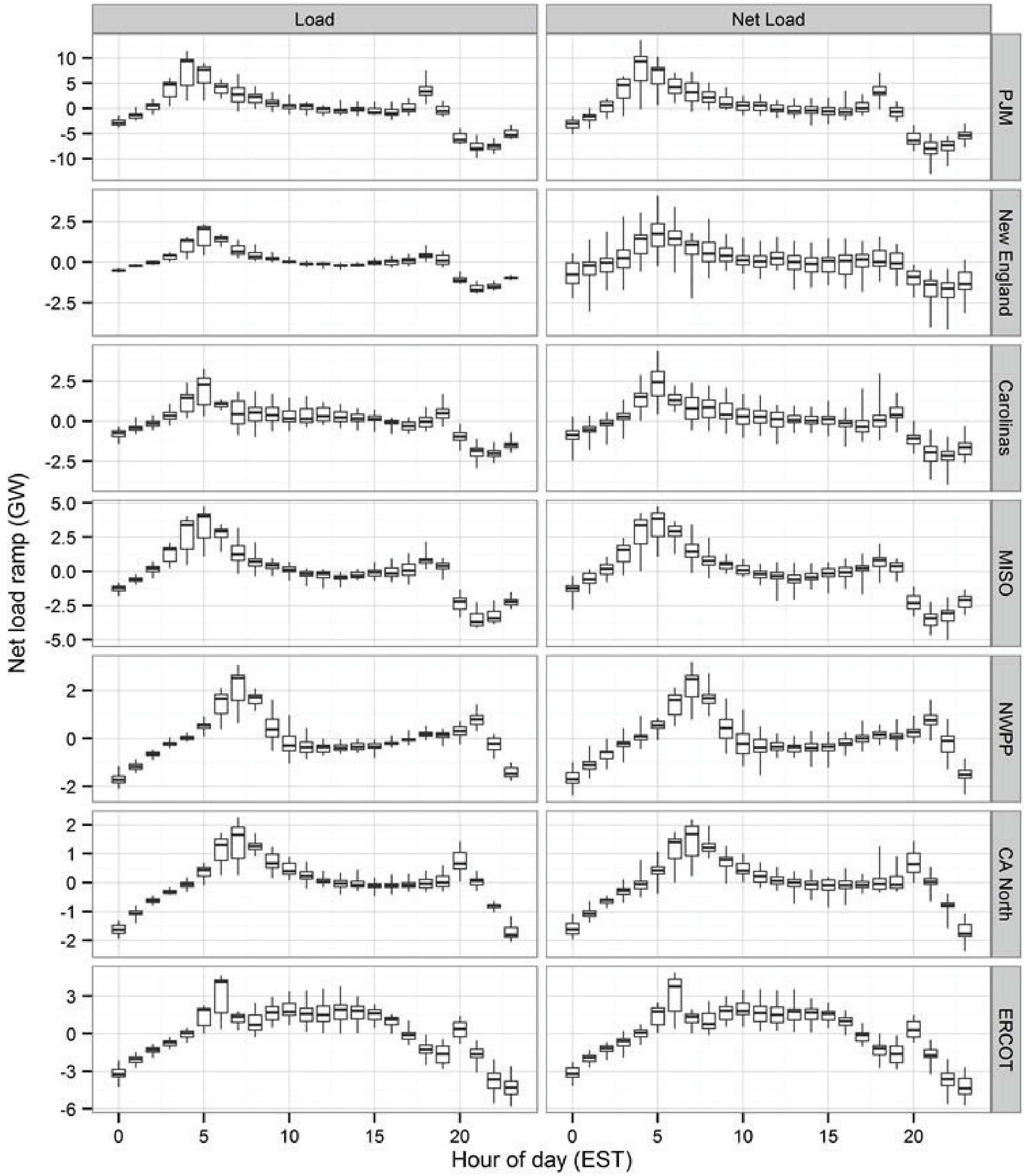

Figure B-2. Boxplots showing load and net load hourly variability by hour of day for April 2006

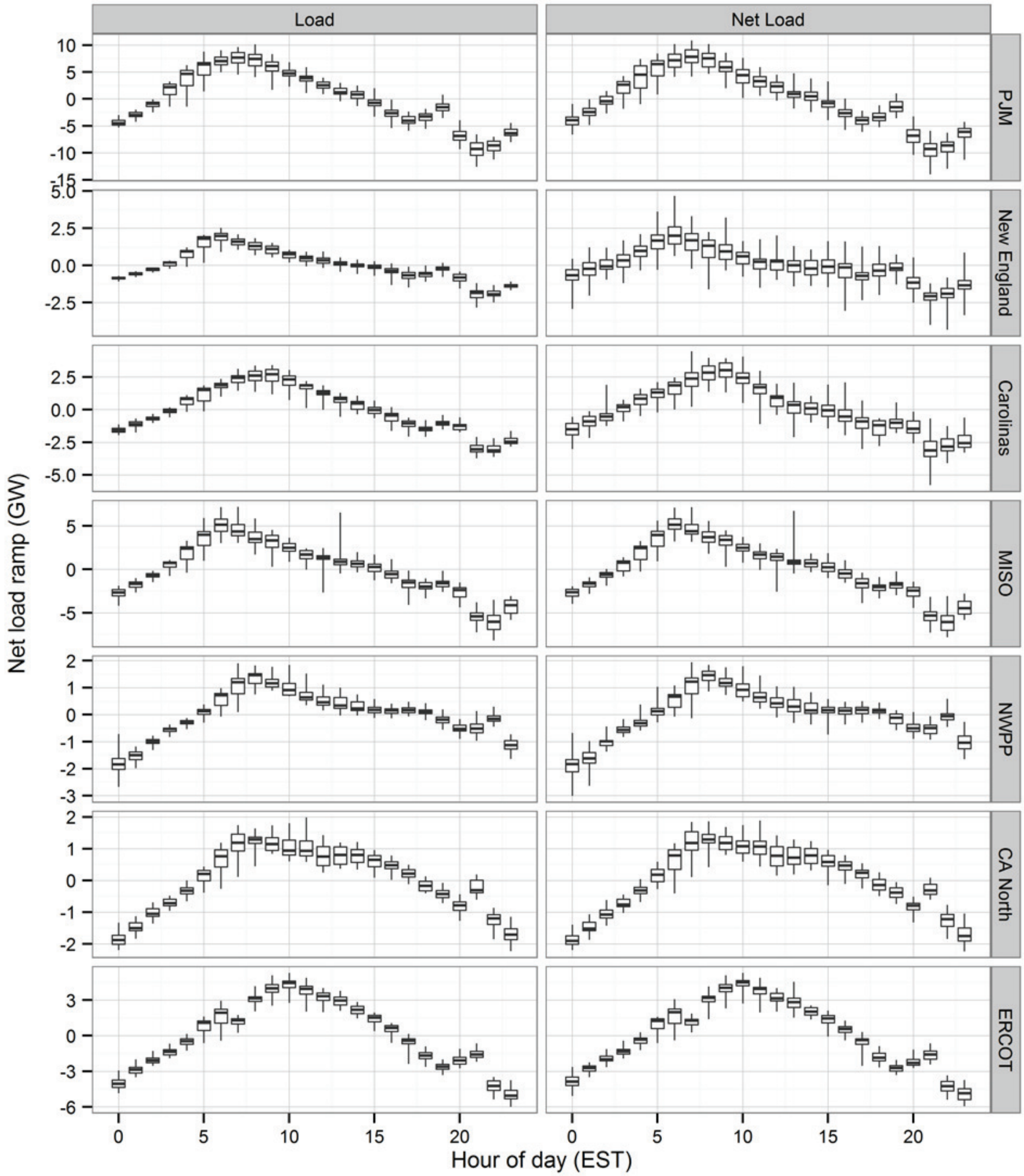

Figure B-3. Boxplots showing load and net load hourly variability by hour of day for July 2006

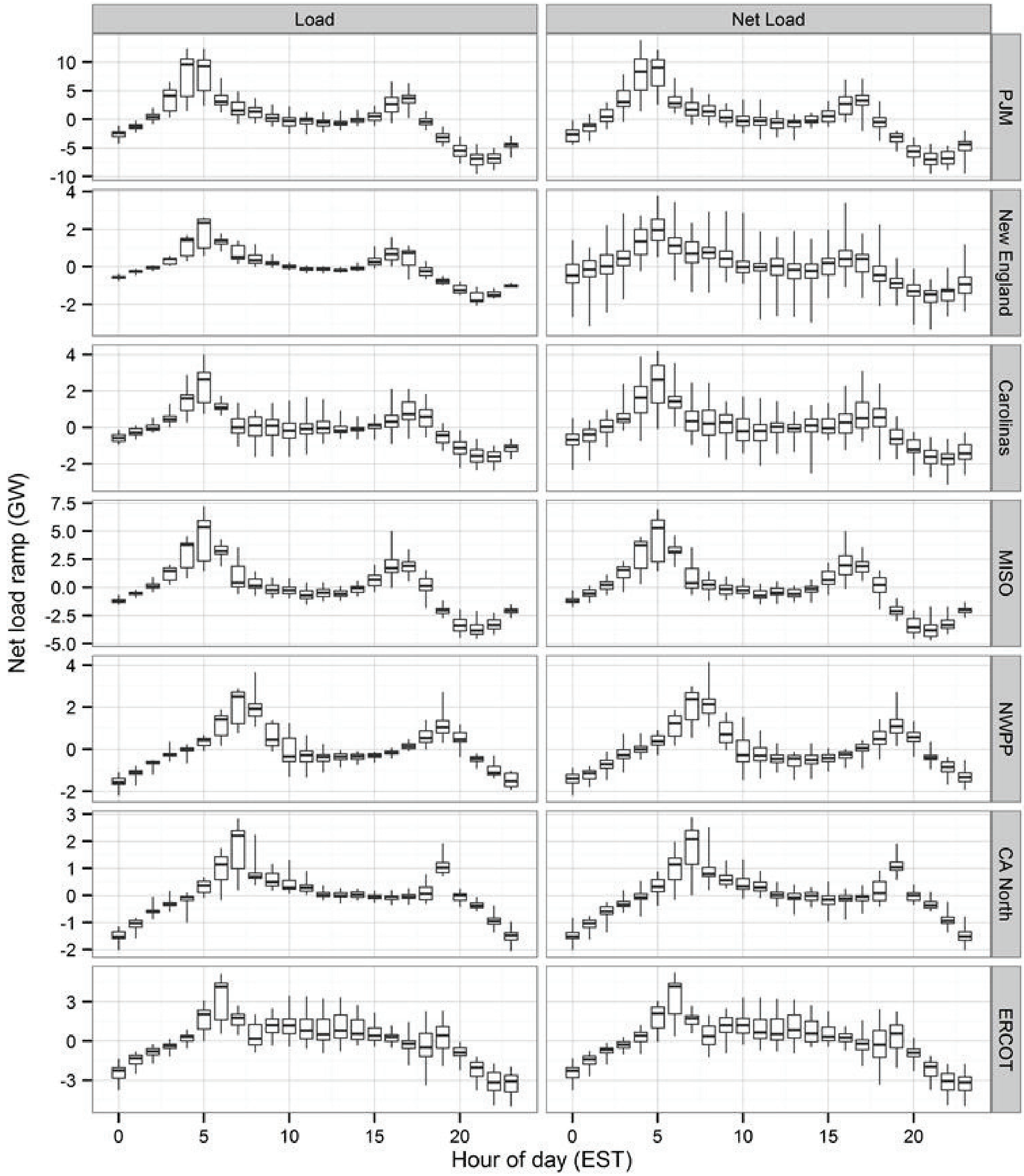

Figure B-4. Boxplots showing load and net load hourly variability by hour of day for October 2006

B.2 Contour Plots Showing Load and Net Load Power

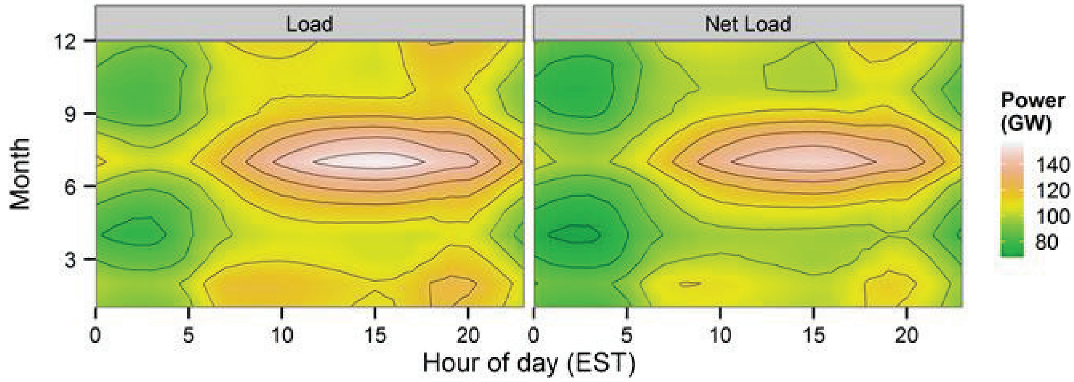

Figure B-5. Contour plots showing average load and net load by month and hour of day for PJM

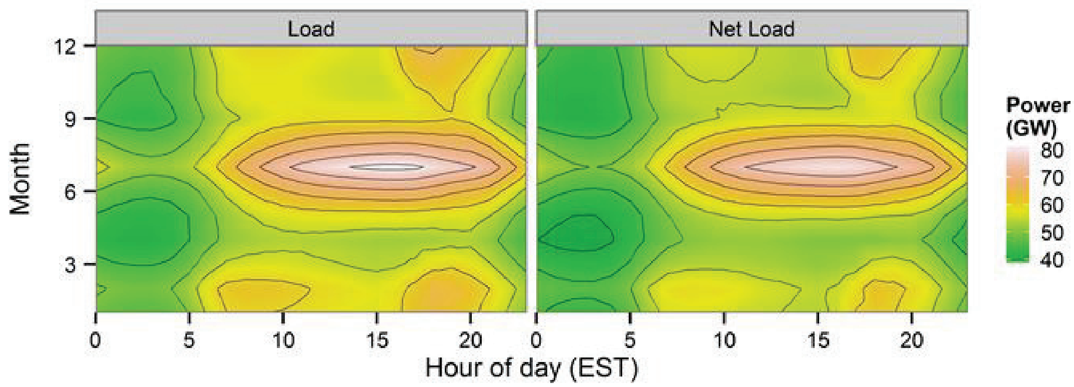

Figure B-6. Contour plots showing average load and net load by month and hour of day for MISO

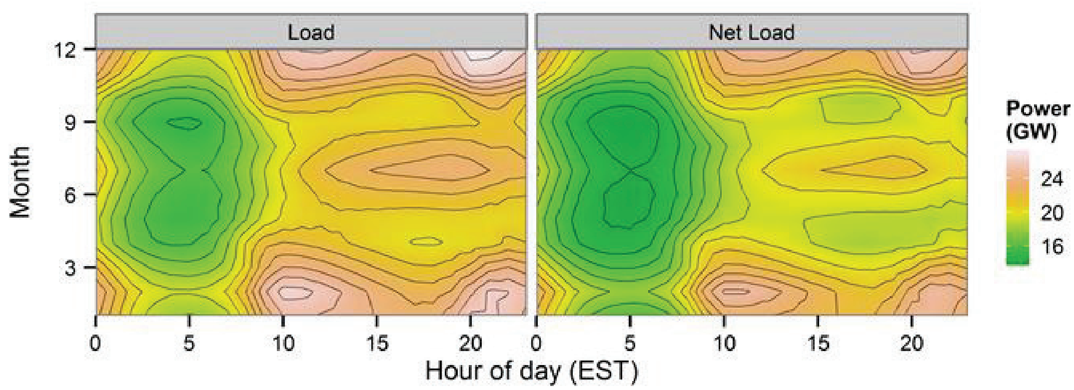

Figure B-7. Contour plots showing average load and net load by month and hour of day for NWPP

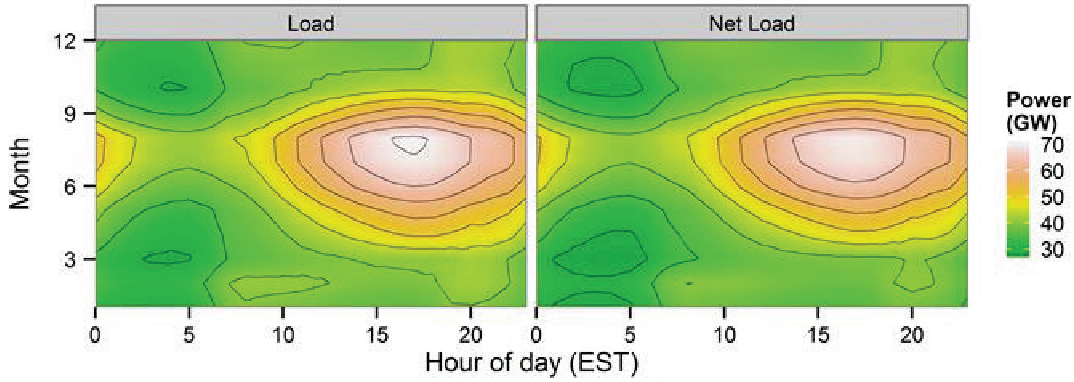

Figure B-8. Contour plots showing average load and net load by month and hour of day for ERCOT

B.3 Contour Plots Showing Load and Net Load Variability

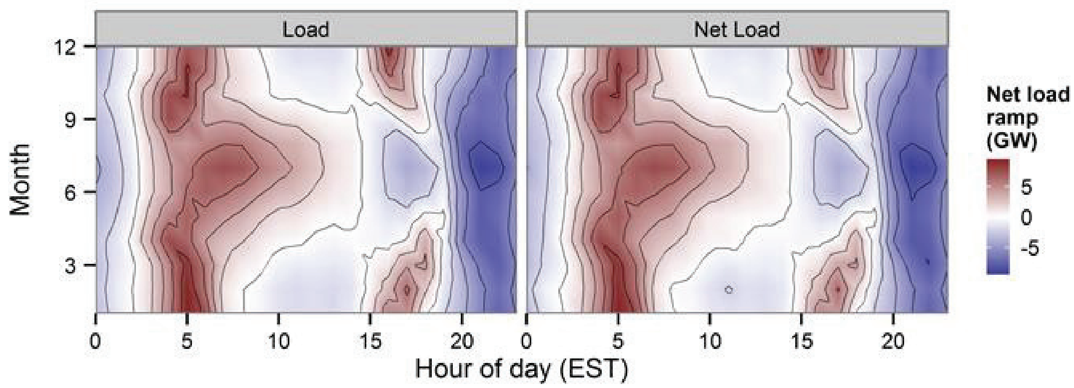

Figure B-9. Contour plots showing average load and net load ramp by month and hour of day for PJM

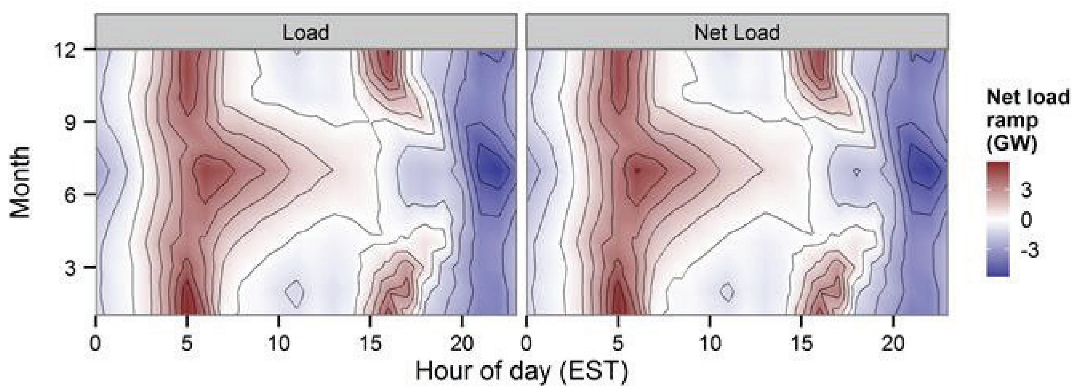

Figure B-10. Contour plots showing average load and net load ramp by month and hour of day for MISO

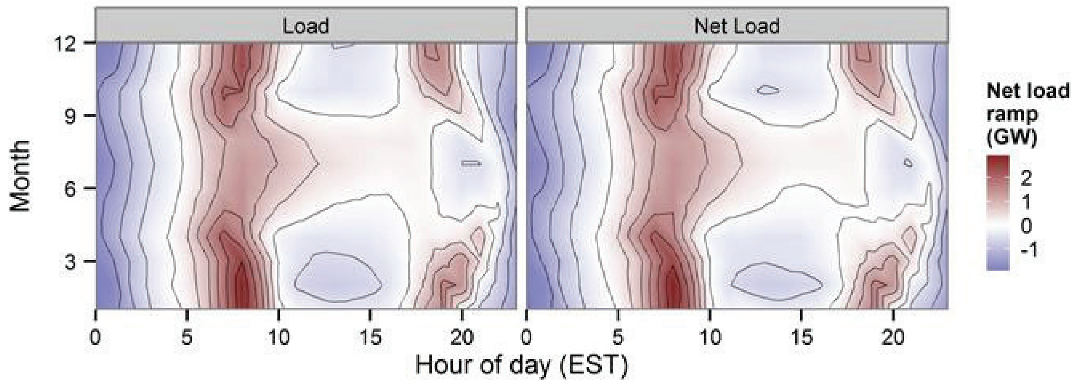

Figure B-11. Contour plots showing average load and net load ramp by month and hour of day for NWPP

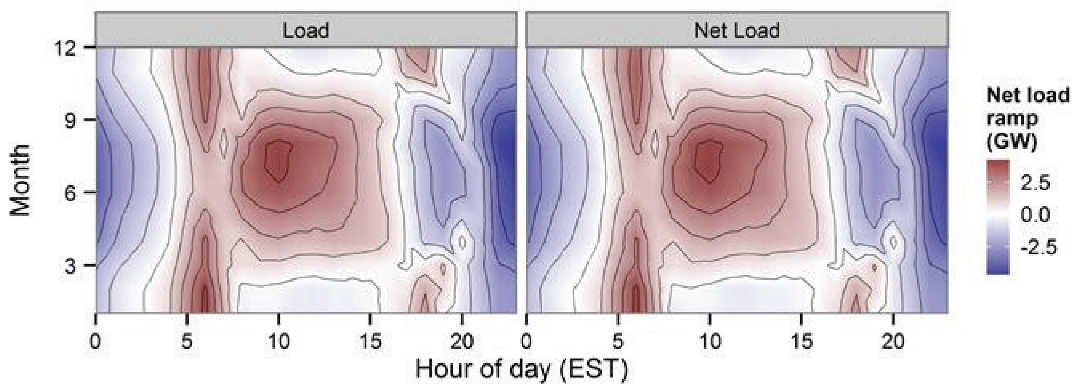

Figure B-12. Contour plots showing average load and net load ramp by month and hour of day for ERCOT

APPENDIX C—REGIONAL TOPOLOGY COMPARISON RESULT SUMMARIES

C.1 ERCOT

Table C-1. ERCOT Thermal Violations with 30% Offshore Wind Output—827 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
Lon C Hill - Orange Grove 138kV	Sigmor - San Migual 138 kV	211	1.00	1.05	0.05	11
Coleto Creek - Kenedy 138 kV	Coleto Creek - Pawnee 345 kV	207	0.93	1.04	0.10	21

Table C-2. ERCOT Thermal Violations with 50% Offshore Wind Output—1,378 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
Lon C Hill - Orange Grove 138kV	Lon C Hill - Pawnee 345 kV	211	0.92	1.10	0.18	38
Coleto Creek - Kenedy 138 kV	Coleto Creek - Pawnee 345 kV	207	0.93	1.11	0.17	36
Westside - Cabaniss 138 kV	Holly - Rodd Field 138 kV	320	0.95	1.03	0.09	28

Table C-3. ERCOT Thermal Violations with 100% Offshore Wind Output—2,755 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
Lon C Hill - Orange Grove 138 kV	Pawnee - Lon C Hill 345 kV	211	0.92	1.29	0.37	77
Pawnee 345/138 kV	J K Spruce - Pawnee 345 kV	150	0.78	1.11	0.33	50
Pawnee - Lon C Hill 345 kV	South Texas POI Tap - Nopalito 345 kV	1011	0.38	1.06	0.68	687
Airco CSW - Union Carbide 138 kV	South Texas POI Tap - Nopalito 345 kV	157	0.54	1.10	0.57	89
Airco CSW - Rincon 138 kV	South Texas POI Tap - Nopalito 345 kV	157	0.53	1.11	0.57	90
Coleto Creek - Kenedy 138 kV	Coleto Creek - Pawnee 345 kV	207	0.93	1.29	0.35	73
La Palma 345/138 kV	Rio Hondo - North Edinburg 345 kV	660	0.53	1.01	0.47	312
Rio Hondo - Burns 138 kV	Rio Hondo - North Edinburg 345 kV	174	0.37	1.16	0.79	137
Westside - Cabaniss 138 kV	Holly - Rodd Field 138 kV	320	0.95	1.12	0.18	57
Holly - Rodd Field 138 kV	Airline - Cabaniss 138 kV	320	0.92	1.08	0.16	51
Airline - Cabaniss 138 kV	Lon C Hill - Nelson Sharpe 345 kV	320	0.49	1.05	0.56	179
Celanese Bishop - Nelson Sharpe 138 kV	Lon C Hill - Nelson Sharpe 345 kV	211	0.42	1.06	0.64	136
Celanese Bishop - Kleberg 138 kV	Lon C Hill - Nelson Sharpe 345 kV	211	0.41	1.05	0.64	135
Burns - Heildelberg 138 kV	Rio Hondo - North Edinburg 345 kV	174	0.25	1.05	0.79	138
Milo - Laredo 138 kV	Laredo - Del Mar 138 kV	257	0.84	1.03	0.19	49

C.2 ISO-NE

Table C-4. ISO-NE Thermal Violations with 30% Offshore Wind Output—4,361 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
DEERFIELD - 2 345/115 kV	TF_DRFD_TB14	522	0.9	1.02	0.1	47.88
PEQUONIC - SING1955PEQ - 1 115 kV	DC_387_1537	677	1	1.04	0.1	41.15

Table C-5. ISO-NE Thermal Violations with 50% Offshore Wind Output—7,269 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
DEERFIELD - 2 345/115 kV	BF_SCOB_802	522	0.92	1.09	0.17	88
SCOBIE POND - 30 345/99 kV	BF_DRFD_182	543	0.93	1.03	0.11	58
SCOBIE T30 - 30 115/99 kV	BF_DRFD_182	543	0.92	1.03	0.11	58
WASH_TAP 510 - BAKER ST PS1 - 1 115 kV	BF_K-ST_103	159	0.41	1.02	0.61	97
WASH_TAP 511 - BAKER ST PS2 - 1 115 kV	BF_K-ST_103	159	0.40	1.01	0.61	97
SANDY POND - 1 345/99 kV	BF_SNDPD_337	572	0.76	1.00	0.24	139
HADDAM NECK - MONTVILLE - 1 345 kV	SPS_MILLSTN4	1912	0.35	1.09	0.75	1434
MONTVILLE - MILLSTONE - 1 345 kV	SPS_MILLSTN4	1912	0.43	1.33	0.90	1728
PEQUONIC - SING1955PEQ - 1 115 kV	DC_387_1537	677	0.98	1.10	0.12	80

Table C-6. ISO-NE Thermal Violations with 100% Offshore Wind Output—14,537 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
ORRINGTON - ORRNGTN SCAP - 2 345 kV	LN_388	1429	0.49	1.16	0.67	958
ORRINGTON - COOPERS MILL - 1 345 kV	BF_ALBI_24T1	1429.4	0.44	1.01	0.57	816
ORRNGTN SCAP - ALBION ROAD - 1 345 kV	LN_388	1429.4	0.49	1.17	0.68	970
COOPERS MILL - MAINE YANKEE - 1 345 kV	LN_3025	1429.4	0.55	1.08	0.54	766
DETROIT - BUCKSPORT - 1 115 kV	SPS_388_MISL	192.8	0.41	1.34	0.94	180
DETROIT - ALBION ROAD - 1 115 kV	SPS_388_MISL	233	0.59	1.15	0.56	131
SEA STRATTON - CMP_215A_SEA - 1 115 kV	SPS_388_MISL	232	0.14	1.15	1.01	234
BIGELOW - CMP_215A_SEA - 1 115 kV	SPS_388_MISL	233	0.14	1.14	1.00	234
DEERFIELD - 2 345/115 kV	BF_SCOB_802	522	0.92	1.34	0.41	216
NU_363_SBK - SCOBIE POND - 1 345 kV	BF_WDHL_T-94	1494	0.73	1.14	0.41	608
SCOBIE POND - 30 345/99 kV	BF_DRFD_182	543	0.93	1.19	0.26	143
SCOBIE POND - SCOBIE T30 - 1 115 kV	BF_DRFD_182	643	0.77	1.01	0.24	152
SCOBIE T30 - 30 115/99 kV	BF_DRFD_182	543	0.92	1.19	0.26	142
JORDAN ROAD - CANAL - 1 345 kV	BF_CANAL_212	1446	0.17	1.73	1.56	2249
HYDE PARK - 1 345/115 kV	BF_K-ST_103	600	0.64	1.04	0.39	235
WASH_TAP 510 - BAKER ST PS1 - 1 115 kV	BF_K-ST_103	159	0.41	1.25	0.84	134

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
WASH_TAP 511 - BAKER ST PS2 - 1 115 kV	BF_K-ST_103	159	0.40	1.25	0.84	134
NEEDHAM - DOVER MA - 1 115 kV	SPS_316_3161	494	0.66	1.10	0.44	217
DOVER MA - WEST WALPOLE - 1 115 kV	SPS_316_3161	530	0.71	1.11	0.40	213
CARVER - CANAL - 1 345 kV	BF_CANAL_312	1221	0.18	2.00	1.82	2225
CARVER - NGR_356_NST - 1 345 kV	DC_342_194	1410	0.02	1.06	1.04	1465
TREMONT N - WAREHAM 113 - 1 115 kV	BF_CANAL_412	246	0.09	1.07	0.98	242
VALLEYNB 113 - WAREHAM 113 - 1 115 kV	BF_CANAL_412	246	0.09	1.07	0.99	242
VALLEYNB 113 - HORSEPDTP113 - 1 115 kV	BF_CANAL_412	246	0.10	1.10	1.00	246
HORSEPDTP108 - VALLEYNB 108 - 1 115 kV	BF_CANAL_412	246	0.15	1.17	1.02	251
HORSEPDTP108 - BOURNE - 1 115 kV	BF_CANAL_412	246	0.26	1.28	1.03	253
WAREHAM 108 - VALLEYNB 108 - 1 115 kV	BF_CANAL_412	246	0.10	1.09	0.99	244
HORSEPDTP113 - BOURNE - 1 115 kV	BF_CANAL_412	246	0.10	1.10	1.00	246
CANAL - 1 345/115 kV	BF_CANAL_312	470	0.23	1.08	0.86	402
CANAL - SITE_20 - 1 345 kV	DC_342_355	1000		1.05		
BOURNE - CANAL 126 - 1 115 kV	BF_CANAL_312	463	0.22	1.04	0.82	380
SANDY POND - 1 345/99 kV	BF_SNDPD_337	572	0.76	1.13	0.38	215
SANDY POND - 1 115/99 kV	BF_SNDPD_337	572	0.75	1.12	0.37	212
BRAYTN POINT - 1 345/115 kV	BF_BYPT_3-3T	580	0.28	1.24	0.96	557
BRAYTN POINT - BERRY STREET - 1 345 kV	LN_315	1157	0.17	1.08	0.91	1058
BRAYTN POINT - WEST FARNUM - 1 345 kV	BF_BYPT_3-3T	1404	0.11	1.29	1.18	1652
NG451-536NST - AUBURN ST N. - 1 115 kV	LN_335	359	0.25	1.09	0.85	304
CARD - MILLSTONE - 1 345 kV	DC_310S_348	1912	0.38	1.00	0.62	1192
CARD - MILLSTONE - 2 345 kV	DC_371_383	1912	0.45	1.17	0.73	1393
SCOVILLE RCK - HADDAM NECK - 1 345 kV	SPS_MILLSTN4	1912	0.16	1.20	1.04	1986
HADDAM NECK - MONTVILLE - 1 345 kV	SPS_MILLSTN4	1912	0.35	2.02	1.67	3200
MONTVILLE - MILLSTONE - 1 345 kV	SPS_MILLSTN4	1912	0.43	2.45	2.02	3870
MILLSTONE - HADDAM_T - 1 345 kV	DC_371_383	1912	0.63	1.39	0.76	1457
MILLSTONE - SITE_16 - 1 345 kV	SPS_MILLSTN4	1000		1.60		
HADDAM_T - BESECK - 1 345 kV	DC_371_383	1912	0.53	1.25	0.72	1383
E.SHORE - 8 345/115 kV	TF_ESHORE_9X	575	0.81	1.09	0.28	162
E.SHORE - 9 345/115 kV	TF_ESHORE_8X	575	0.81	1.09	0.28	162
PEQUONIC - SING1955PEQ - 1 115 kV	DC_387_1537	677	0.98	1.24	0.26	176
SEA STRATTON - T1 345/115 kV	SPS_388_MISL	100	0.06	1.27	1.21	121
SEA STRATTON - T2 345/115 kV	SPS_388_MISL	100	0.06	1.27	1.21	121
BELFAST - T1 345/115 kV	SPS_388_MISL	100	0.00	1.88	1.88	188
BELFAST - T2 345/115 kV	SPS_388_MISL	100	0.00	1.88	1.88	188

C.3 MISO

Table C-7. MISO Thermal Violations with 30% Offshore Wind Output—724 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
PLS PR2 - ZION ; R - 1 345 kV	KENOSH45 - LAKEVIEW - 1 138 kV	1069	0.99	1.08	0.09	100
EMPIRE6 - PRESQ IS - 1 138 kV	EMPIRE2 - EMPIRE3 - Z 138 kV	166	0.78	1.08	0.30	49

Table C-8. MISO Thermal Violations with 50% Offshore Wind Output—1,207 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
PLS PR2 - ZION ; R - 1 345 kV	KENOSH45 - LAKEVIEW - 1 138 kV	1069	0.99	1.14	0.15	162
GRANVL3 - 1 345/138 kV	GRANVL2 - GRANVL1 - Z 345 kV	478	0.86	1.03	0.17	82
EMPIRE2 - EMPIRE3 - Z 138 kV	EMPIRE6 - PRESQ IS - 1 138 kV	185	0.67	1.14	0.47	87
EMPIRE3 - EMPIRE4 - Z 138 kV	EMPIRE6 - PRESQ IS - 1 138 kV	185	0.57	1.04	0.47	86
EMPIRE5 - EMPIRE6 - Z 138 kV	EMPIRE2 - EMPIRE3 - Z 138 kV	185	0.62	1.06	0.44	81
EMPIRE6 - PRESQ IS - 1 138 kV	EMPIRE2 - EMPIRE3 - Z 138 kV	166	0.78	1.27	0.49	82
PLAINS - 1 138/100 kV	ARNOLD - FORSYTH - 1 138 kV	359	0.51	1.03	0.52	186
DEAD RVR - PLAINS - 1 345 kV	ARNOLD - FORSYTH - 1 138 kV	468	0.15	1.05	0.89	418
PLAINS - 1 345/100 kV	ARNOLD - FORSYTH - 1 138 kV	359	0.49	1.02	0.54	192

Table C-9. MISO Thermal Violations with 100% Offshore Wind Output—2,413 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
LSUAMICO - STILES4 - 1 138 kV	STILES5 - PULLIAM - 2 138 kV	204	0.25	1.11	0.86	176
LSUAMICO - PULLIAM - 1 138 kV	STILES5 - PULLIAM - 2 138 kV	204	0.25	1.10	0.85	174
PLS PR2 - ZION ; R - 1 345 kV	KENOSH45 - LAKEVIEW - 1 138 kV	1069	0.99	1.27	0.28	297
GRANVL3 - 1 345/138 kV	GRANVL2 - GRANVL1 - Z 345 kV	478	0.86	1.18	0.32	151
STILES5 - PULLIAM - 2 138 kV	LSUAMICO - STILES4 - 1 138 kV	204	0.25	1.11	0.86	175
EMPIRE2 - EMPIRE3 - Z 138 kV	EMPIRE6 - PRESQ IS - 1 138 kV	185	0.67	1.71	1.03	191
EMPIRE2 - EMPIRE1 - Z 138 kV	EMPIRE6 - PRESQ IS - 1 138 kV	185	0.43	1.17	0.75	138
EMPIRE3 - EMPIRE4 - Z 138 kV	EMPIRE6 - PRESQ IS - 1 138 kV	185	0.57	1.60	1.02	190
EMPIRE4 - EMPIRE5 - Z 138 kV	EMPIRE2 - EMPIRE3 - Z 138 kV	185	0.53	1.47	0.94	175
EMPIRE4 - FORSYTH - 1 138 kV	NORDIC - PERCH LK - 1 138 kV	300	0.25	1.03	0.78	233
EMPIRE5 - EMPIRE6 - Z 138 kV	EMPIRE2 - EMPIRE3 - Z 138 kV	185	0.62	1.59	0.97	179
EMPIRE6 - PRESQ IS - 1 138 kV	EMPIRE2 - EMPIRE3 - Z 138 kV	166	0.78	1.88	1.10	182
GRANVL 5 - GRANVL 6 - Z 138 kV	GRANVL2 - GRANVL1 - Z 345 kV	566	0.68	1.07	0.39	220
MORGAN - PLAINS - 1 345 kV	ER MUNI - LAKOTA R - 1 115 kV	717	0.21	1.88	1.68	1201
PLAINS - 1 138/100 kV	ARNOLD - FORSYTH - 1 138 kV	359	0.51	1.46	0.95	342
MORGAN - WH CLAY - 1 138 kV	WERNER W - HIWAY 22 - 1 345 kV	332	0.09	1.01	0.93	308

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
WH CLAY - WH CLAY1 - Z 138 kV	WERNER W - HIWAY 22 - 1 345 kV	300	0.17	1.03	0.86	258
ARNOLD - FORSYTH - 1 138 kV	NORDIC - PERCH LK - 1 138 kV	245	0.19	1.02	0.83	204
NORTH LK - M-38 138 - 1 138 kV	PERCH LK - PRESQ IS - 1 138 kV	96	0.47	1.42	0.94	91
EMPIRE1 - NATIONAL - 1 138 kV	EMPIRE6 - PRESQ IS - 1 138 kV	202	0.44	1.13	0.69	140
PERCH LK - PRESQ IS - 1 138 kV	NORTH LK - M-38 138 - 1 138 kV	202	0.30	1.04	0.73	148
DEAD RVR - PLAINS - 1 345 kV	ARNOLD - FORSYTH - 1 138 kV	468	0.15	2.14	1.99	932
PLAINS - 1 345/100 kV	ARNOLD - FORSYTH - 1 138 kV	359	0.49	1.51	1.02	367
PLAINS - SITE_4049 - 1 345 kV	ARNOLD - FORSYTH - 1 138 kV	807		1.15		

C.4 CAROLINAS

Table C-10. Carolinas Thermal Violations with 30% Offshore Wind Output—2,484 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
6CASTLEH230T - 6WILM OGDEN - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	478	0.68	1.42	0.74	352
6WILM OGDEN - 6WRIGHTSVILL - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	557	0.69	1.33	0.64	355

Table C-11. Carolinas Thermal Violations with 50% Offshore Wind Output—4,140 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
6BRUN2 230 T - 6WALLACE230T - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.54	1.01	0.47	225
6BRUN2 230 T - 6E1-PROSPECT - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	557	0.44	1.15	0.71	396
6BRUN2 230 T - 6E1-SOUTHPOR - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.52	1.18	0.66	315
6CASTLEH230T - 6SCOTT TAP - 1 230.0 kV	6WALLACE230T - 6E9-W ONSLOW - 1 230 kV	557	0.78	1.11	0.33	182
6CASTLEH230T - 6WILM OGDEN - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	478	0.68	1.96	1.28	611
6DELCO230 T - 6E1-SOUTHPOR - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.38	1.03	0.65	310
6WILM OGDEN - 6WRIGHTSVILL - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	557	0.69	1.79	1.10	614

Table C-12. Carolinas Thermal Violations with 100% Offshore Wind Output—8,281 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
6BRUN2 230 T - 6WALLACE230T - 1 230 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.54	1.66	1.12	536
6BRUN2 230 T - 6E1-PROSPECT - 1 230 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	557	0.44	2.08	1.64	913
6BRUN2 230 T - 6E1-SOUTHPOR - 1 230 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.52	2.05	1.53	730
6BRUN1 230 T - 6WSPOON230 T - 1 230 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	478	0.24	1.33	1.09	521
6BRUN1 230 T - 6PEC IND033 - 1 230 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	478	0.76	1.05	0.30	142
3SUTTON115 T - 3PEC IND060 - 1 115 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	159	0.39	1.32	0.93	148
6SUTTON230 T - 6PEC IND053 - 1 230 kV	3PEC IND054 - 3CASTLEH115T - 1 115 kV	478	0.58	1.42	0.83	399
3WSPOON115 T - 3BLADENBORO - 1 115 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	145	0.10	1.30	1.20	174
6CLINTON230T - 1 230/115 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	200	0.29	1.11	0.82	163
6CLINTON230T - 6WARSAW TAP - 1 230 kV	3BEULAVILLE - 3WALLACE115T - 1 115 kV	539	0.10	1.62	1.53	824
3MT OLIVE TA - 3MT OLV WEST - 1 115 kV	6LEESUB230 T - 6MTOLIVE230T - 1 230 kV	148	0.27	1.27	1.00	148
3MT OLIVE TA - 3MTOLIVE115T - 1 115 kV	6LEESUB230 T - 6MTOLIVE230T - 1 230 kV	125	0.30	1.61	1.31	164
3KORNEGAY SU - 3KORNEGAY TA - 1 115 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	109	0.23	1.52	1.29	141
3BEULAVILLE - 3WALLACE115T - 1 115 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	78	0.32	2.26	1.94	151
3BEULAVILLE - 3E17-BEULAVI - 1 115 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	89	0.20	1.85	1.65	147
6PEC IND033 - 6E9-MEADOW - 1 230 kV	6BRUN1 230 T - 6PEC IND069 - 1 230 kV	478	0.71	1.01	0.30	144
6CUMBLND230T - 6GARLAND - 1 230 kV	3CLARKTON - 3ELIZAB TAP - 1 115 kV	478	0.05	1.68	1.63	777
6CUMBLND230T - 6E4-TARHELL - 1 230 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.07	1.03	0.95	455

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
6AURORA SS T - 6E16-SLVRHIL - 1 230 kV	6PA-GREENVLT - 6PEC IND043 - 1 230 kV	478	0.43	1.11	0.68	325
6NEW BERN W - 6NEWBERN230T - 1 230 kV	6PA-GREENVLT - 6PEC IND043 - 1 230 kV	478	0.59	1.29	0.71	338
6NEW BERN W - 6E16-SLVRHIL - 1 230 kV	6PA-GREENVLT - 6PEC IND043 - 1 230 kV	478	0.50	1.20	0.69	331
6NEWBERN230T - 6CC WD EN TA - 1 230 kV	3JACKSON115T - 3E9-GUMBRNCH - 1 115 kV	478	0.43	1.43	1.00	478
6NEWBERN230T - 6HAVELOK230T - 1 230 kV	3PEC IND042 - 3CHERY PT TA - 1 115 kV	478	0.36	1.29	0.93	444
3NEWBERN115T - 3PEC IND044 - 1 115 kV	6NEW BERN W - 6E16-SLVRHIL - 1 230 kV	159	0.10	1.06	0.97	154
6CC WD EN TA - 6RHEMS - 1 230 kV	3JACKSON115T - 3E9-GUMBRNCH - 1 115 kV	557	0.29	1.17	0.88	488
3PEC IND044 - 3PEC IND046 - 1 115 kV	6NEW BERN W - 6E16-SLVRHIL - 1 230 kV	147	0.03	1.05	1.02	150
3PEC IND046 - 3PEC IND049 - 1 115 kV	6NEW BERN W - 6E16-SLVRHIL - 1 230 kV	147	0.03	1.02	0.99	146
6HAVELOK230T - 6MORHDWW230T - 1 230 kV	6MORHDWW230T - 3MORHDWW115T - 1 230/115 kV	598	0.01	1.71	1.71	1021
6MORHDWW230T - 1 230/115 kV	6HAVELOK230T - 3HAVELOK115T - 1 230/115 kV	300	0.54	1.17	0.63	188
6MORHDWW230T - SITE_150 - 1 230 kV	6MORHDWW230T - 3MORHDWW115T - 1 230/115 kV	1000		1.02		
6ROSE HILL - 6E4-BEVERAGE - 1 230 kV	3BEULAVILLE - 3WALLACE115T - 1 115 kV	717	0.13	1.31	1.17	842
6ROSE HILL - 6E4-BLIND BR - 1 230 kV	3BEULAVILLE - 3WALLACE115T - 1 115 kV	637	0.13	1.44	1.31	836
3WOMMACK115T - 3E9-PLEASANT - 1 115 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	150	0.21	1.25	1.04	156
3WALLACE TAP - 3BURGAW SUB - 1 115 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	131	0.11	1.40	1.28	168
3WALLACE TAP - 3WALLACE115T - 1 115 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	159	0.09	1.15	1.06	168
3BURGAW SUB - 3PEC IND054 - 1 115 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	120	0.28	1.73	1.45	174
6WALLACE230T - 6PEC IND052 - 1 230 kV	3PEC IND054 - 3CASTLEH115T - 1 115 kV	478	0.50	1.31	0.81	389
6WALLACE230T - 6E4-BEVERAGE - 1 230 kV	3BEULAVILLE - 3WALLACE115T - 1 115 kV	637	0.24	1.59	1.35	862
6PEC IND052 - 6PEC IND055 - 1 230 kV	3PEC IND054 - 3CASTLEH115T - 1 115 kV	557	0.43	1.13	0.70	390
6WARSAW TAP - 6E4-BLIND BR - 1 230 kV	3BEULAVILLE - 3WALLACE115T - 1 115 kV	539	0.15	1.69	1.55	834
6PEC IND053 - 6PEC IND055 - 1 230 kV	3PEC IND054 - 3CASTLEH115T - 1 115 kV	478	0.51	1.33	0.82	392
6JACKSON230T - 6RHEMS - 1 230 kV	3JACKSON115T - 3E9-GUMBRNCH - 1 115 kV	478	0.39	1.41	1.02	489
6JACKSON230T - 6GEIGER TAP - 1 230 kV	3FOLKSTN115T - 3E9-DAWSON - 1 115 kV	557	0.45	1.28	0.84	466
3JACKSON115T - 3E9-GUMBRNCH - 1 115 kV	6NEW BERN W - 6E16-SLVRHIL - 1 230 kV	150	0.24	1.56	1.32	198
3PEC IND054 - 3CASTLEH115T - 1 115 kV	6WALLACE230T - 3WALLACE115T - 1 230/115 kV	131	0.65	1.73	1.08	141
6GEIGER TAP - 6FOLKSTN230T - 1 230 kV	3FOLKSTN115T - 3E9-DAWSON - 1 115 kV	557	0.49	1.33	0.84	468
6FOLKSTN230T - 6TOPSAIL TAP - 1 230 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	557	0.43	1.51	1.09	605
6CASTLEH230T - 1 230/115 kV	3CASTLEH115T - 6CASTLEH230T - 2 115/230 kV	200	0.21	1.68	1.46	293
6CASTLEH230T - 2 230/115 kV	3CASTLEH115T - 6CASTLEH230T - 1 115/230 kV	300	0.16	1.27	1.11	333
6CASTLEH230T - 6SCOTT TAP - 1 230 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	557	0.54	1.64	1.10	613
6CASTLEH230T - 6MURRAYVILLE - 1 230 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	590	0.12	1.10	0.98	579
6CASTLEH230T - 6WILM OGDEN - 1 230 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	478	0.68	3.56	2.88	1377
6WILM EAST - 6MURRAYVILLE - 1 230 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	590	0.16	1.05	0.89	525
6TOPSAIL TAP - 6SCOTT TAP - 1 230 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	590	0.46	1.50	1.03	610

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
3PEC IND060 - 3EAGLE ISLAN - 1 115 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	179	0.30	1.13	0.82	147
3DELCO115 T - 3LAKE WACCA - 1 115 kV	3CLARKTON - 3ELIZAB TAP - 1 115 kV	179	0.05	1.14	1.09	195
3DELCO115 T - 3PEC IND065 - 1 115 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	161	0.10	1.29	1.19	192
3CLARKTON - 3ELIZAB TAP - 1 115 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	161	0.12	1.19	1.07	173
3CLARKTON - 3PEC IND065 - 1 115 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	161	0.10	1.27	1.17	188
3ELIZAB TAP - 3BLADENBORO - 1 115 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	161	0.08	1.22	1.14	184
3LAKE WACCA - 3E1-HALLSBOR - 1 115 kV	3CLARKTON - 3ELIZAB TAP - 1 115 kV	179	0.05	1.04	1.00	179
3WHITEVIL TA - 3E1-HALLSBOR - 1 115 kV	3CLARKTON - 3ELIZAB TAP - 1 115 kV	179	0.06	1.03	0.97	173
6DELCO230 T - 6E1-SOUTHPOR - 1 230 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.38	1.89	1.50	718
6DELCO230 T - 6E4-KELLY - 1 230 kV	3CLARKTON - 3ELIZAB TAP - 1 115 kV	478	0.13	1.85	1.73	825
6GARLAND - 6E4-KELLY - 1 230 kV	3CLARKTON - 3ELIZAB TAP - 1 115 kV	557	0.05	1.50	1.45	810
6WHITEVL230T - 6E1-PROSPECT - 1 230 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	557	0.09	1.60	1.51	842
6WHITEVL230T - 6E4-POWELL - 1 230 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.08	1.16	1.08	514
6MASONBORO - 6WRIGHTSVILL - 1 230 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	637	0.61	1.00	0.39	249
6WILM OGDEN - 6WRIGHTSVILL - 1 230 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	557	0.69	3.17	2.48	1384
6E4-POWELL - 6E4-TARHELL - 1 230 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	507	0.04	1.04	1.01	512
3E9-EAGLES - 3E9-GUMBRNCH - 1 115 kV	6NEWBERN230T - 6WOMMACK230T - 2 230 kV	150	0.07	1.45	1.38	208
3E9-EAGLES - 3E9-PLEASANT - 1 115 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	150	0.19	1.27	1.07	161
3E17-BEULAVI - 3E17-PINKHIL - 1 115 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	92	0.20	1.75	1.55	143
6BUCKSVL - 6PERRY R - 1 230 kV	6BUCKSVL - 6PERRY R - 2 230 kV	765	0.74	1.05	0.31	240
6BUCKSVL - 6PERRY R - 2 230 kV	6BUCKSVL - 6PERRY R - 1 230 kV	797	0.71	1.01	0.30	240
6GOOS CK - 6PEPPERHILL - 1 230 kV	6GOOS CK - 3GOOS CK - 1 230/115 kV	510	0.04	1.18	1.14	582
6GOOS CK - 1 230/115 kV	6GOOS CK - 6PEPPERHILL - 1 230 kV	336	0.39	1.28	0.89	300

Table C-13. Carolinas Thermal Violations with 100% Offshore Wind Output [Duke Upgrade]—8,281 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
6BRUN2 230 T - 6WALLACE230T - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.54	1.65	1.11	533
6BRUN2 230 T - 6E1-PROSPECT - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	557	0.44	2.06	1.62	903
6BRUN2 230 T - 6E1-SOUTHPOR - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.52	2.04	1.52	725
6BRUN1 230 T - 6WSPOON230 T - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	478	0.24	1.32	1.08	515
6BRUN1 230 T - 6PEC IND033 - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	478	0.76	1.05	0.30	142
3SUTTON115 T - 3PEC IND060 - 1 115.0 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	159	0.39	1.30	0.92	146
6SUTTON230 T - 6PEC IND053 - 1 230.0 kV	3PEC IND054 - 3CASTLEH115T - 1 115 kV	478	0.58	1.41	0.83	395
3WSPOON115 T - 3BLADENBORO - 1 115.0 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	145	0.10	1.28	1.18	172
6CLINTON230T - 1 230.0/115.0 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	200	0.29	1.11	0.81	163
6CLINTON230T - 6WARSAW TAP - 1 230.0 kV	6WALLACE230T - 6E9-W ONSLOW - 1 230 kV	539	0.21	1.61	1.40	755
3MT OLIVE TA - 3MT OLV WEST - 1 115.0 kV	6LEESUB230 T - 6MTOLIVE230T - 1 230 kV	148	0.27	1.25	0.99	146
3MT OLIVE TA - 3MTOLIVE115T - 1 115.0 kV	6LEESUB230 T - 6MTOLIVE230T - 1 230 kV	125	0.30	1.59	1.30	162

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
3BEULAVILLE - 3WALLACE115T - 1 115.0 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	78	0.32	2.23	1.91	149
3BEULAVILLE - 3E17-BEULAVI - 1 115.0 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	89	0.20	1.83	1.63	145
6PEC IND033 - 6E9-MEADOW - 1 230.0 kV	6BRUN1 230 T - 6PEC IND069 - 1 230 kV	478	0.71	1.01	0.30	144
6CUMBLND230T - 6GARLAND - 1 230.0 kV	3DELCO115 T - 3PEC IND065 - 1 115 kV	478	0.05	1.69	1.64	782
6CUMBLND230T - 6E4-TARHELL - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.07	1.02	0.95	452
6PA-WASH - 6E16-EDWARDS - 1 230.0 kV	6PA-GREENVLT - 6PEC IND043 - 1 230 kV	478	0.29	1.01	0.72	346
6AURORA SS T - 6E16-EDWARDS - 1 230.0 kV	6PA-GREENVLT - 6PEC IND043 - 1 230 kV	478	0.31	1.04	0.73	348
6AURORA SS T - 6E16-SLVRHIL - 1 230.0 kV	6PA-GREENVLT - 6PEC IND043 - 1 230 kV	478	0.43	1.20	0.77	368
6NEW BERN W - 6NEWBERN230T - 2 230.0 kV	6NEW BERN W - 6NEWBERN230T - 1 230 kV	499		1.05		0
6NEWBERN230T - 6CC WD EN TA - 1 230.0 kV	3JACKSON115T - 3E9-GUMBRNCH - 1 115 kV	478	0.43	1.45	1.01	484
6NEWBERN230T - 6HAVELOK230T - 1 230.0 kV	3PEC IND042 - 3CHERY PT TA - 1 115 kV	478	0.36	1.30	0.93	446
3NEWBERN115T - 3PEC IND044 - 1 115.0 kV	6AURORA SS T - 6E16-SLVRHIL - 1 230 kV	159	0.06	1.02	0.96	153
6CC WD EN TA - 6RHEMS - 1 230.0 kV	3JACKSON115T - 3E9-GUMBRNCH - 1 115 kV	557	0.29	1.18	0.89	494
3PEC IND044 - 3PEC IND046 - 1 115.0 kV	6AURORA SS T - 6E16-SLVRHIL - 1 230 kV	147	0.05	1.00	0.96	141
6HAVELOK230T - 6MORHDWW230T - 1 230.0 kV	6MORHDWW230T - 3MORHDWW115T - 1 230/115 kV	598	0.01	1.70	1.69	1013
6MORHDWW230T - 1 230.0/115.0 kV	6HAVELOK230T - 3HAVELOK115T - 1 230/115 kV	300	0.54	1.17	0.63	188
6MORHDWW230T - SITE_150 - 1 230.0 kV	6MORHDWW230T - 3MORHDWW115T - 1 230/115 kV	1000		1.02		0
6ROSE HILL - 6E4-BEVERAGE - 1 230.0 kV	6WALLACE230T - 6E9-W ONSLOW - 1 230 kV	717	0.23	1.29	1.06	762
6ROSE HILL - 6E4-BLIND BR - 1 230.0 kV	6WALLACE230T - 6E9-W ONSLOW - 1 230 kV	637	0.24	1.43	1.19	759
3WOMMACK115T - 3E9-PLEASANT - 1 115.0 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	150	0.21	1.24	1.02	154
3WALLACE TAP - 3BURGAW SUB - 1 115.0 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	131	0.11	1.38	1.27	166
3WALLACE TAP - 3WALLACE115T - 1 115.0 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	159	0.09	1.14	1.05	167
3BURGAW SUB - 3PEC IND054 - 1 115.0 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	120	0.28	1.71	1.43	172
6WALLACE230T - 6PEC IND052 - 1 230.0 kV	3PEC IND054 - 3CASTLEH115T - 1 115 kV	478	0.50	1.31	0.81	386
6WALLACE230T - 6E4-BEVERAGE - 1 230.0 kV	6WALLACE230T - 6E9-W ONSLOW - 1 230 kV	637	0.35	1.57	1.22	775
6PEC IND052 - 6PEC IND055 - 1 230.0 kV	3PEC IND054 - 3CASTLEH115T - 1 115 kV	557	0.43	1.12	0.69	386
6WARSAW TAP - 6E4-BLIND BR - 1 230.0 kV	6WALLACE230T - 6E9-W ONSLOW - 1 230 kV	539	0.27	1.68	1.41	758
6PEC IND053 - 6PEC IND055 - 1 230.0 kV	3PEC IND054 - 3CASTLEH115T - 1 115 kV	478	0.51	1.32	0.81	388
6JACKSON230T - 6RHEMS - 1 230.0 kV	3JACKSON115T - 3E9-GUMBRNCH - 1 115 kV	478	0.39	1.42	1.04	495
6JACKSON230T - 6GEIGER TAP - 1 230.0 kV	3FOLKSTN115T - 3E9-DAWSON - 1 115 kV	557	0.45	1.29	0.84	467
3JACKSON115T - 3E9-GUMBRNCH - 1 115.0 kV	6NEWBERN230T - 6WOMMACK230T - 2 230 kV	150	0.14	1.54	1.40	211
3PEC IND054 - 3CASTLEH115T - 1 115.0 kV	6WALLACE230T - 3WALLACE115T - 1 230/115 kV	131	0.65	1.72	1.07	140
6GEIGER TAP - 6FOLKSTN230T - 1 230.0 kV	3FOLKSTN115T - 3E9-DAWSON - 1 115 kV	557	0.49	1.33	0.84	469
6FOLKSTN230T - 6TOPSAIL TAP - 1 230.0 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	557	0.43	1.51	1.08	601
6CASTLEH230T - 1 230.0/115.0 kV	3CASTLEH115T - 6CASTLEH230T - 2 115/230 kV	200	0.21	1.67	1.46	292
6CASTLEH230T - 2 230.0/115.0 kV	3CASTLEH115T - 6CASTLEH230T - 1 115/230 kV	300	0.16	1.27	1.11	333
6CASTLEH230T - 6SCOTT TAP - 1 230.0 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	557	0.54	1.64	1.09	609
6CASTLEH230T - 6MURRAYVILLE - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	590	0.12	1.09	0.97	574
6CASTLEH230T - 6WILM OGDEN - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	478	0.68	3.54	2.86	1367

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
6WILM EAST - 6MURRAYVILLE - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	590	0.16	1.04	0.88	520
6TOPSAIL TAP - 6SCOTT TAP - 1 230.0 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	590	0.46	1.49	1.03	606
3PEC IND060 - 3EAGLE ISLAN - 1 115.0 kV	6SUTTON230 T - 6WILM 9&O TA - 1 230 kV	179	0.30	1.11	0.81	145
3DELCO115 T - 3LAKE WACCA - 1 115.0 kV	3DELCO115 T - 3PEC IND065 - 1 115 kV	179	0.06	1.15	1.09	196
3DELCO115 T - 3PEC IND065 - 1 115.0 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	161	0.10	1.28	1.18	190
3CLARKTON - 3ELIZAB TAP - 1 115.0 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	161	0.12	1.18	1.06	171
3CLARKTON - 3PEC IND065 - 1 115.0 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	161	0.10	1.26	1.16	186
3ELIZAB TAP - 3BLADENBORO - 1 115.0 kV	3DELCO115 T - 3LAKE WACCA - 1 115 kV	161	0.08	1.21	1.13	182
3LAKE WACCA - 3E1-HALLSBOR - 1 115.0 kV	3DELCO115 T - 3PEC IND065 - 1 115 kV	179	0.04	1.06	1.02	182
3WHITEVIL TA - 3E1-HALLSBOR - 1 115.0 kV	3DELCO115 T - 3PEC IND065 - 1 115 kV	179	0.05	1.04	0.99	177
6DELCO230 T - 6E1-SOUTHPOR - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.38	1.88	1.49	713
6DELCO230 T - 6E4-KELLY - 1 230.0 kV	3DELCO115 T - 3PEC IND065 - 1 115 kV	478	0.13	1.86	1.73	825
6GARLAND - 6E4-KELLY - 1 230.0 kV	3DELCO115 T - 3PEC IND065 - 1 115 kV	557	0.05	1.51	1.46	812
6WHITEVL230T - 6E1-PROSPECT - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	557	0.09	1.59	1.50	835
6WHITEVL230T - 6E4-POWELL - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	478	0.08	1.15	1.07	511
6WILM OGDEN - 6WRIGHTSVILL - 1 230.0 kV	6DELCO230 T - 6PEC IND069 - 1 230 kV	557	0.69	3.16	2.47	1374
6E4-POWELL - 6E4-TARHELL - 1 230.0 kV	6WILM WIN PR - 6WILM CEDAR - 1 230 kV	507	0.04	1.04	1.00	509
3E9-EAGLES - 3E9-GUMBRNCH - 1 115.0 kV	6NEWBERN230T - 6WOMMACK230T - 2 230 kV	150	0.07	1.43	1.36	204
3E9-EAGLES - 3E9-PLEASANT - 1 115.0 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	150	0.19	1.25	1.05	158
3E17-BEULAVI - 3E17-PINKHIL - 1 115.0 kV	6CLINTON230T - 6MTOLIVE230T - 1 230 kV	92	0.20	1.72	1.53	141
6PERRY R - 3 230.0/115.0 kV	6CARFOR - 6PERRY R - 1 230 kV	300		1.17		0
6GOOS CK - 6PEPPERHILL - 1 230.0 kV	6GOOS CK - 3GOOS CK - 1 230/115 kV	510	0.04	1.18	1.14	582
6GOOS CK - 1 230.0/115.0 kV	6GOOS CK - 6PEPPERHILL - 1 230 kV	336	0.39	1.28	0.89	300

C.5 PJM

Table C-14. PJM Thermal Violations with 30% Offshore Wind Output—6,127 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
BRIGHTON - 1 500/230 kV	01DOUBS - 01KEMPTOWN - 1 500 kV	1406	0.97	1.01	0.03	49
MANITOU - OYSTER C - 1 230 kV	MANITOU - OYSTER C - 2 230 kV	805	0.99	1.45	0.47	375
MANITOU - OYSTER C - 2 230 kV	MANITOU - OYSTER C - 1 230 kV	805	0.99	1.45	0.47	375
CHICHST1 - EDDYSTN4 - 1 230 kV	FOULK - FOULK8 - 1 230 kV	863	0.99	1.25	0.26	227
CHICHST2 - LINWOOD - 1 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	983	0.76	1.04	0.28	275
CHICHST2 - LINWOOD - 2 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	983	0.80	1.09	0.29	288
DELCOTAP - MCKLTON - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	725	0.90	1.01	0.11	79
LINWOOD - CLAY_230 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.89	1.21	0.32	261
LINWOOD - EDGEMR 5 - 1 230 kV	CLAY_230 - EDGEMR 5 - 1 230 kV	805	0.96	1.25	0.29	236
W.CALD G - KNGLND G - 1 230 kV	SMITHBRG - MANALAPN - 1 230 kV	269	0.94	1.23	0.29	79
CUTHBERT - GLOUCSTR - 1 230 kV	NEW FREE - WINDSOR - 1 500 kV	500	0.98	1.28	0.29	147
CUTHBERT - CAMDEN - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	500	0.70	1.04	0.33	167
THOROFAR - MCKLTON - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	566	0.91	1.08	0.17	98
NWEST326 - CONASTON - 1 230 kV	NWEST311 - CONASTON - 1 230 kV	874	0.93	1.03	0.10	88
CLAY_230 - EDGEMR 5 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.97	1.26	0.29	236
HARMONY - KEEN_230 - 1 230 kV	HARMONY - KEEN_230 - 2 230 kV	739	0.73	1.01	0.28	207
HARMONY - KEEN_230 - 2 230 kV	HARMONY - KEEN_230 - 1 230 kV	739	0.83	1.14	0.32	233
RL_230 - CEDAR CK - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	679	0.15	1.14	0.98	668
COLOR_PE - CECIL - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	179	0.64	1.39	0.75	134
STEELE - MILF_230 - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	551	0.21	1.32	1.11	610
STEELE - VIENNA - 1 230 kV	STEELE - VIENNA - 2 230 kV	551	0.88	1.59	0.71	393
STEELE - VIENNA - 2 230 kV	STEELE - VIENNA - 1 230 kV	551	0.88	1.59	0.71	393
COOLSPGS - MILF_230 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.45	1.77	1.32	1061
COOLSPGS - INDRIV 4 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.60	1.86	1.26	1014
MILF_230 - INDRIV 4 - 2 230kV	COOLSPGS - MILF_230 - 1 230 kV	805	0.49	1.81	1.31	1058
02S8-ATT - 8 345/138 kV	02AT - 02PERRY - 1 345 kV	370	0.39	1.04	0.65	241
6KITY H1 - 1 230/115 kV	6KITY H1 - 6KITY H2 - 1 230 kV	203	0.58	1.01	0.43	87

Table C-15. PJM Thermal Violations with 50% Offshore Wind Output—10,212 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
BRIGHTON - 1 500/230 kV	01DOUBS - 01KEMPTOWN - 1 500 kV	1406	0.97	1.03	0.05	77
YORKANA - BRIS - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	617	0.80	1.04	0.24	149
ATLANTIC - LARRABEE - 1F 230 kV	SMITHBRG - MANALAPN - 1 230 kV	841	0.67	1.04	0.37	307
LARRABEE - LAKEWOOD - 1 230 kV	LARRABEE - LAKEWOOD - 2 230 kV	805	0.63	1.16	0.53	425
LARRABEE - LAKEWOOD - 2 230 kV	LARRABEE - LAKEWOOD - 1 230 kV	805	0.63	1.16	0.53	425
MANITOU - OYSTER C - 1 230 kV	MANITOU - OYSTER C - 2 230 kV	805	0.99	1.78	0.79	636
MANITOU - OYSTER C - 2 230 kV	MANITOU - OYSTER C - 1 230 kV	805	0.99	1.78	0.79	636
CHICHST1 - EDDYSTN4 - 1 230 kV	FOULK - FOULK8 - 1 230 kV	863	0.99	1.41	0.42	366
CHICHST1 - FOULK8 - 1 230 kV	CHICHST1 - EDDYSTN4 - 1 230 kV	1079	0.73	1.03	0.30	324
CHICHST2 - LINWOOD - 1 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	983	0.76	1.22	0.46	452
CHICHST2 - LINWOOD - 2 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	983	0.80	1.28	0.48	474
DELCOTAP - MCKLTON - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	725	0.90	1.07	0.17	126
LINWOOD - CLAY_230 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.89	1.41	0.52	420
LINWOOD - EDGEMR 5 - 1 230 kV	CLAY_230 - EDGEMR 5 - 1 230 kV	805	0.96	1.43	0.47	380
CUTHBERT - GLOUCSTR - 1 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	500	0.56	1.32	0.76	382
CUTHBERT - CAMDEN - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	500	0.79	1.37	0.58	290
THOROFAR - MCKLTON - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	566	0.93	1.22	0.29	165
NWEST326 - CONASTON - 1 230 kV	NWEST311 - CONASTON - 1 230 kV	874	0.93	1.09	0.16	143
GRACETON - BAGLEY - 1 230 kV	CNASTONE - 01KEMPTOWN - 1 500 kV	674	0.68	1.12	0.44	297
RAPHAEL - BAGLEY - 1 230 kV	CNASTONE - 01KEMPTOWN - 1 500 kV	674	0.59	1.03	0.44	296
CARDIFF - 1 230/16 kV	OYSTER C - CEDAR - 1 230 kV	150	0.35	1.00	0.65	98
CLAY_230 - EDGEMR 5 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.97	1.44	0.47	381
EDGEMR 5 - HARMONY - 1 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	932	0.33	1.15	0.82	765
HARMONY - KEEN_230 - 1 230 kV	HARMONY - KEEN_230 - 2 230 kV	739	0.73	1.21	0.47	348
HARMONY - KEEN_230 - 2 230 kV	HARMONY - KEEN_230 - 1 230 kV	739	0.83	1.36	0.53	392
KEEN_230 - STEELE - 1 230 kV	KEEN_230 - STEELE - 2 230 kV	695	0.23	1.34	1.11	773
KEEN_230 - STEELE - 2 230 kV	MILF_230 - MAGNL230 - 1 230 kV	805	0.21	1.39	1.19	956
RL_230 - CEDAR CK - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	679	0.15	1.85	1.69	1149
RL_230 - CARTANZA - 1 230 kV	RL_230 - CEDAR CK - 1 230 kV	790	0.15	1.32	1.17	928
COLOR_PE - CECIL - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	179	0.66	1.90	1.24	222
STEELE - MILF_230 - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	551	0.21	2.35	2.14	1181
STEELE - VIENNA - 1 230 kV	STEELE - VIENNA - 2 230 kV	551	0.88	2.06	1.18	648
STEELE - VIENNA - 2 230 kV	STEELE - VIENNA - 1 230 kV	551	0.88	2.06	1.18	648
COOLSPGS - MILF_230 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.45	2.67	2.22	1783
COOLSPGS - INDRIV 4 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.60	2.72	2.12	1705
CEDAR CK - MILF_230 - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	679	0.20	1.54	1.34	908
CARTANZA - MAGNL230 - 1 230 kV	RL_230 - CEDAR CK - 1 230 kV	805	0.12	1.28	1.17	941
MILF_230 - INDRIV 4 - 2 230 kV	COOLSPGS - MILF_230 - 1 230 kV	805	0.49	2.71	2.22	1785
MILF_230 - MAGNL230 - 1 230 kV	RL_230 - CEDAR CK - 1 230 kV	805	0.14	1.47	1.33	1071
INDRIV 4 - PINEY GR - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	621	0.21	1.63	1.43	885
INDRIV 4 - 1 230/138 kV	COOLSPGS - INDRIV 4 - 1 230 kV	478	0.42	1.04	0.62	299

INDRIV 4 - 3 230/138 kV	COOLSPGS - INDRIV 4 - 1 230 kV	478	0.40	1.05	0.66	314
PINEY GR - LOR_230 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.08	1.07	0.99	797
02S8-ATT - 8 345/138 kV	02AT - 02PERRY - 1 345 kV	370	0.39	1.45	1.05	390
6BOWERS - 6CHRHLND - 1 230 kV	6SMITFLD - 6SURRY - 1 230 kV	722	0.10	1.12	1.02	739
6BOWERS - 6YADKIN - 1 230 kV	6SMITFLD - 6SURRY - 1 230 kV	722	0.17	1.06	0.90	649
6CHRHLND - 6SEWLSPT - 1 230 kV	6CHRHLND - 6SEWLSPT - 2 230 kV	531	0.76	1.68	0.93	492
6CHRHLND - 6SEWLSPT - 2 230 kV	6CHRHLND - 6SEWLSPT - 1 230 kV	600	0.67	1.49	0.82	493
6SEWLSPT - 1 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	264	0.31	1.35	1.04	275
6SEWLSPT - 2 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	264	0.32	1.34	1.03	272
6AYDLETT - 6POINTHB - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	409	0.78	1.04	0.26	106
6POINTHB - 6KITY H2 - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	409	0.75	1.07	0.32	130
6KITY H1 - 1 230/115 kV	6KITY H1 - 6KITY H2 - 1 230 kV	203	0.58	1.30	0.72	146
6KITY H1 - 6SHAWBRO - 1 230 kV	6POINTHB - 6KITY H2 - 1 230 kV	409	0.74	1.07	0.33	135

Table C-16. PJM Thermal Violations with 100% Offshore Wind Output—20,425 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
BRIGHTON - 1 500/230 kV	01DOUBS - 01KEMPTOWN - 1 500kV	1406	0.97	1.07	0.10	137
CNASTONE - PEACHBTM - 1 500 kV	PEACHBTM - 3 Mi I - 1 500 kV	2815	0.43	1.32	0.89	2496
KEENEY - ROCKSPGS - 1 500 kV	CHICHST1 - CHICHST2 - 1 230 kV	3014	0.06	1.05	0.98	2962
PEACHBTM - ROCKSPGS - 1 500 kV	CHICHST1 - CHICHST2 - 1 230 kV	2931	0.18	1.27	1.09	3198
REDLION - 1 500/230 kV	REDLION - RL_230 - 2 500/230 kV	1037	0.11	1.14	1.03	1065
REDLION - 2 500/230 kV	REDLION - RL_230 - 1 500/230 kV	1064	0.13	1.30	1.17	1242
JACKSON - TMI - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	591	0.62	1.09	0.47	279
YORKANA - BRIS - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	617	0.80	1.26	0.46	283
ATLANTIC - LARRABEE - 1F 230 kV	SMITHBRG - NEWPROSP - 1 230 kV	841	0.80	1.21	0.40	338
ATLANTIC - NEWPROSP - 1 230 kV	ATLANTIC - LARRABEE - 1F 230 kV	731	0.77	1.01	0.24	177
LARRABEE - LAKEWOOD - 1 230 kV	LARRABEE - LAKEWOOD - 2 230 kV	805	0.63	1.70	1.07	862
LARRABEE - LAKEWOOD - 2 230 kV	LARRABEE - LAKEWOOD - 1 230 kV	805	0.63	1.70	1.07	861
LEISUR D - MANITOU - 1 230 kV	LEISUR U - MANITOU - 1 230 kV	805	0.36	1.47	1.11	892
LEISUR D - LAKEWOOD - 1 230 kV	LEISUR U - MANITOU - 1 230 kV	805	0.22	1.32	1.10	881
LEISUR U - MANITOU - 1 230 kV	LEISUR D - MANITOU - 1 230 kV	805	0.36	1.47	1.11	892
LEISUR U - LAKEWOOD - 1 230 kV	LEISUR D - MANITOU - 1 230 kV	805	0.23	1.33	1.09	881
MANITOU - OYSTER C - 1 230 kV	MANITOU - OYSTER C - 2 230 kV	805	0.99	2.67	1.68	1354
MANITOU - OYSTER C - 2 230 kV	MANITOU - OYSTER C - 1 230 kV	805	0.99	2.67	1.68	1354
OYSTER C - CEDAR - 1 230 kV	NEW FREE - WINDSOR - 1 500 kV	800	0.02	1.96	1.94	1554
WINDSOR - E WINDSR - 1 230 kV	DEANS - WINDSOR - 1 500 kV	772	0.49	1.04	0.55	424
NLAN - SAKR - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	588	0.67	1.15	0.49	286
CHICHST1 - EDDYSTN4 - 1 230 kV	CONCORD6 - FOULK - 1 230 kV	863	0.99	1.77	0.79	680
CHICHST1 - FOULK8 - 1 230 kV	CHICHST1 - EDDYSTN4 - 1 230 kV	1079	0.73	1.28	0.56	600
CHICHST2 - LINWOOD - 1 230 kV	NEW FREE - WINDSOR - 1 500 kV	983	0.82	1.24	0.42	413
CHICHST2 - LINWOOD - 2 230 kV	NEW FREE - WINDSOR - 1 500 kV	983	0.86	1.30	0.44	433
CHIREACT - TRAINER - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	841	0.75	1.00	0.26	216

CONCORD6 - FOULK - 1 230 kV	CHICHST1 - EDDYSTN4 - 1 230 kV	1079	0.69	1.24	0.56	600
CONOWG03 - NOTTNGHM - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	570	0.59	1.15	0.56	320
DELCOTAP - MCKLTON - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	725	0.90	1.19	0.29	208
LINWOOD - CLAY_230 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.89	1.83	0.94	760
LINWOOD - EDGEMR 5 - 1 230 kV	CLAY_230 - EDGEMR 5 - 1 230 kV	805	0.96	1.81	0.86	689
NOTTNGHM - NOTTREAC - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	567	0.27	1.25	0.98	557
NOTTREAC - PCHBTMTP - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	578	0.27	1.23	0.96	557
PARRISH9 - TUNNEL - 1 230 kV	CONCORD - CONCORD4 - 1 230 kV	905	0.61	1.05	0.44	401
PCHBTMTP - COOPER - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	578	0.27	1.23	0.96	556
PRINTZ - RIDLEY - 1 230 kV	EDDYSTN - EDDYSTN3 - 1 230 kV	1505	0.82	1.01	0.19	283
RICHMOND - WANEETA3 - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	863	0.43	1.06	0.63	544
RICHMOND - CAMDEN - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	831	0.46	1.14	0.69	569
TUNNEL2 - GRAYSFRY4 - 1 230 kV	CONCORD - CONCORD4 - 1 230 kV	983	0.60	1.00	0.41	400
COOPER - GRACETON - 1 230 kV	CNASTONE - PEACHBTM - 1 500 kV	485	0.27	1.42	1.15	558
W.CALD G - KNGLND G - 1 230 kV	HOPATCONG - ROSELD - 1 500 kV	269	0.73	1.26	0.53	142
HUDSN1-6 - SITE_43 - 1 230 kV	BERGEN - BGN_COLL - 1 230 kV	1000		1.00		
NEW FRDM - BEAVR BK - 1 230 kV	NEW FREE - WINDSOR - 1 500 kV	752	0.59	1.07	0.48	361
CUTHBERT - GLOUCSTR - 1 230 kV	NEW FREE - WINDSOR - 1 500 kV	500	0.98	1.93	0.94	471
CUTHBERT - CAMDEN - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	500	0.79	1.92	1.13	563
DEPTFORD - THOROFAR - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	740	0.63	1.05	0.42	308
GLOUCSTR - EAGLE PT - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	740	0.71	1.11	0.40	297
THOROFAR - MCKLTON - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	566	0.93	1.49	0.55	314
NWEST326 - CONASTON - 1 230 kV	NWEST311 - CONASTON - 1 230 kV	874	0.93	1.23	0.31	267
NWEST311 - CONASTON - 1 230 kV	NWEST326 - CONASTON - 1 230 kV	976	0.84	1.11	0.27	267
GRACETON - BAGLEY - 1 230 kV	NWEST326 - CONASTON - 1 230 kV	674	0.71	1.19	0.48	325
RAPHAEL - BAGLEY - 1 230 kV	NWEST326 - CONASTON - 1 230 kV	674	0.62	1.10	0.48	325
CARDIFF - 1 230/138 kV	NEW FRDM - CARDIFF - 1 230 kV	425	0.13	1.40	1.28	543
CEDAR - SITE_60 - 1 230 kV	CARDIFF - CEDAR - 1 230 kV	1000		1.84		
CLAY_230 - EDGEMR 5 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.97	1.82	0.86	691
EDGEMR 5 - HARMONY - 1 230 kV	REDLION - HOPE CRK - 1 500 kV	932	0.39	1.20	0.80	747
EDGEMR 5 - 1 230/138 kV	EDGEMR 5 - HARMONY - 1 230 kV	382	0.29	1.34	1.05	400
HARMONY - KEEN_230 - 1 230 kV	HARMONY - KEEN_230 - 2 230 kV	739	0.73	1.54	0.80	595
HARMONY - KEEN_230 - 2 230 kV	HARMONY - KEEN_230 - 1 230 kV	739	0.83	1.73	0.90	669
KEEN_230 - RL_230 - 1 230 kV	KEENEY - REDLION - 1 500 kV	924	0.27	1.37	1.11	1021
KEEN_230 - STEELE - 1 230 kV	KEEN_230 - RL_230 - 1 230 kV	695	0.18	1.59	1.41	979
KEEN_230 - STEELE - 2 230 kV	KEEN_230 - RL_230 - 1 230 kV	805	0.21	1.85	1.64	1322
RL_230 - CEDAR CK - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	679	0.11	2.31	2.20	1492
RL_230 - CARTANZA - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	790	0.13	1.83	1.70	1343
COLOR_PE - CECIL - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	179	0.66	2.93	2.27	406
CECIL - 1 230/138 kV	CHICHST1 - CHICHST2 - 1 230 kV	369	0.41	1.44	1.03	381
STEELE - MILF_230 - 1 230 kV	KEEN_230 - RL_230 - 1 230 kV	551	0.20	2.65	2.44	1346
STEELE - VIENNA - 1 230 kV	SUSQ - SUSQ G1 - 1 230 kV	551	0.53	1.73	1.20	661
STEELE - VIENNA - 2 230 kV	SUSQ - SUSQ G1 - 1 230 kV	551	0.53	1.73	1.20	661

COOLSPGS - MILF_230 - 1 230 kV	SUSQ - SUSQ G1 - 1 230 kV	805	0.24	2.77	2.53	2040
COOLSPGS - INDRIV 4 - 1 230 kV	SUSQ - SUSQ G1 - 1 230 kV	805	0.40	2.93	2.54	2043
CEDAR CK - MILF_230 - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	679	0.16	1.86	1.70	1156
CARTANZA - MAGNL230 - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	805	0.10	1.80	1.70	1369
MILF_230 - INDRIV 4 - 2 230 kV	SUSQ - SUSQ G1 - 1 230 kV	805	0.35	3.03	2.68	2159
MILF_230 - MAGNL230 - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	805	0.12	1.91	1.78	1435
VIENNA - LOR_230 - 1 230 kV	KEEN_230 - RL_230 - 1 230 kV	805	0.09	1.35	1.26	1011
INDRIV 4 - PINEY GR - 1 230 kV	KEEN_230 - RL_230 - 1 230 kV	621	0.15	2.12	1.98	1228
INDRIV 4 - SITE_30 - 1 230 kV	INDR_CAP - INDRIV 4 - 1 230 kV	1000		1.14		
INDRIV 4 - SITE_31 - 1 230 kV	INDR_CAP - INDRIV 4 - 1 230 kV	1000		1.11		
INDRIV 4 - SITE_32 - 1 230 kV	INDR_CAP - INDRIV 4 - 1 230 kV	1000		1.00		
INDRIV 4 - SITE_37 - 1 230 kV	INDR_CAP - INDRIV 4 - 1 230 kV	1000		1.13		
PINEY GR - LOR_230 - 1 230 kV	KEEN_230 - RL_230 - 1 230 kV	805	0.04	1.41	1.37	1101
02AT - 02S8-ATT - 1 345 kV	02AT - 02PERRY - 1 345 kV	772	0.20	1.17	0.98	753.9
02S8-ATT - 8 345/138 kV	02AT - 02PERRY - 1 345 kV	370	0.39	2.43	2.04	754.1
6BOWERS - 6CHRHLND - 1 230 kV	6CHRHLND - 6CRITTDN - 1 230 kV	722	0.59	2.64	2.05	1482
6BOWERS - 6YADKIN - 1 230 kV	6CHRHLND - 6CRITTDN - 1 230 kV	722	0.66	2.57	1.92	1383
6CHRHLND - 1 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	256.8	0.20	1.79	1.58	406.3
6CHRHLND - 6SEWLSPT - 1 230 kV	6CHRHLND - 6SEWLSPT - 2 230 kV	531	0.76	4.02	3.27	1734
6CHRHLND - 6SEWLSPT - 2 230 kV	6CHRHLND - 6SEWLSPT - 1 230 kV	600	0.67	3.56	2.89	1732
6CHRHLND - 6CRITTDN - 1 230 kV	6BOWERS - 6CHRHLND - 1 230 kV	722	0.61	1.61	1.01	725.8
6SEWLSPT - 1 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	263.9	0.31	2.71	2.40	633.4
6SEWLSPT - 2 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	264.1	0.32	2.35	2.04	538.7
6SEWLSPT - SITE_64 - 1 230 kV	6BOWERS - 6CHRHLND - 1 230 kV	1000		1.01		
6CRITTDN - 6SURRY - 1 230 kV	6BOWERS - 6CHRHLND - 1 230 kV	722	0.68	1.53	0.85	616.4
6AYDLETT - 6POINTHB - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	409	0.78	2.82	2.04	834.8
6AYDLETT - 6SHAWBRO - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	478	0.87	2.23	1.36	648.5
6POINTHB - 6KITY H2 - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	409	0.75	2.85	2.10	857.1
6KITY H1 - 1 230/115 kV	6KITY H1 - 6KITY H2 - 1 230 kV	203.1	0.58	2.05	1.47	299.1
6KITY H1 - 6KITY H2 - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	745	0.20	1.76	1.56	1162
6KITY H1 - 6SHAWBRO - 1 230 kV	6POINTHB - 6KITY H2 - 1 230 kV	409	0.74	2.84	2.10	860.7
6KITY H1 - SITE_3 - 1 230 kV	6POINTHB - 6KITY H2 - 1 230 kV	1000		1.46		
6WINFALL - 1 230/115 kV	6SUFFOLK - 6NUCO TP - 1 230 kV	208.5	0.38	1.03	0.66	136.8

Table C-17. PJM Thermal Violations with 50% Offshore Wind Output (HVDC Backbone)—10,212 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
MANITOU - OYSTER C - 1 230 kV	MANITOU - OYSTER C - 2 230 kV	805	0.99	1.07	0.09	69
MANITOU - OYSTER C - 2 230 kV	MANITOU - OYSTER C - 1 230 kV	805	0.99	1.07	0.09	69
CHICHST1 - EDDYSTN4 - 1 230 kV	FOULK - FOULK8 - 1 230 kV	863	0.99	1.21	0.22	189
CHICHST2 - LINWOOD - 1 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	983	0.76	1.00	0.24	239
CHICHST2 - LINWOOD - 2 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	983	0.80	1.05	0.25	250
LINWOOD - CLAY_230 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.89	1.15	0.27	215

LINWOOD - EDGEMR 5 - 1 230 kV	CLAY_230 - EDGEMR 5 - 1 230 kV	805	0.96	1.20	0.24	195
DEANS - BRUNSWK8 - 1 230 kV	SEWAREN - WDBRDG O - 1 230 kV	740	0.82	1.01	0.19	144
CUTHBERT - GLOUCSTR - 1 230 kV	NEW FREE - WINDSOR - 1 500 kV	500	0.98	1.18	0.19	97
CUTHBERT - CAMDEN - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	500	0.79	1.09	0.30	150
THOROFAR - MCKLTON - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	566	0.93	1.06	0.13	76
NWEST326 - CONASTON - 1 230 kV	NWEST311 - CONASTON - 1 230 kV	874	0.93	1.04	0.11	94
CLAY_230 - EDGEMR 5 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.97	1.21	0.24	195
HARMONY - KEEN_230 - 2 230 kV	HARMONY - KEEN_230 - 1 230 kV	739	0.83	1.12	0.29	213
RL_230 - CEDAR CK - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	679	0.15	1.02	0.87	588
COLOR_PE - CECIL - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	179	0.66	1.35	0.69	123
STEELE - MILF_230 - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	551	0.21	1.20	1.00	549
STEELE - VIENNA - 1 230 kV	STEELE - VIENNA - 2 230 kV	551	0.88	1.49	0.61	339
STEELE - VIENNA - 2 230 kV	STEELE - VIENNA - 1 230 kV	551	0.88	1.49	0.61	339
COOLSPGS - MILF_230 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.45	1.61	1.16	934
COOLSPGS - INDRIV 4 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.60	1.71	1.11	892
MILF_230 - INDRIV 4 - 2 230 kV	COOLSPGS - INDRIV 4 - 1 230 kV	805	0.56	1.66	1.10	886
02S8-ATT - 8 345/138 kV	02AT - 02PERRY - 1 345 kV	370	0.39	1.43	1.04	385
6CHRHLND - 6SEWLSPT - 1 230 kV	6CHRHLND - 6SEWLSPT - 2 230 kV	531	0.76	1.44	0.68	360
6CHRHLND - 6SEWLSPT - 2 230 kV	6CHRHLND - 6SEWLSPT - 1 230 kV	600	0.67	1.27	0.60	361
6FENTRES - 6LANDSTN - 1 230 kV	6FENTRES - 6THRS279 - 1 230 kV	722	0.40	1.03	0.64	459
6FENTRES - 6THRS279 - 1 230 kV	6FENTRES - 6LANDSTN - 1 230 kV	637	0.43	1.27	0.84	537
6SEWLSPT - 1 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	264	0.31	1.17	0.86	226
6SEWLSPT - 2 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	264	0.32	1.16	0.84	223
6AYDLETT - 6POINTHB - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	409	0.78	1.02	0.25	102
6POINTHB - 6KITY H2 - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	409	0.75	1.05	0.30	124
6KITY H1 - 1 230/115 kV	6KITY H1 - 6KITY H2 - 1 230 kV	203	0.58	1.30	0.73	148
6KITY H1 - 6SHAWBRO - 1 230 kV	6POINTHB - 6KITY H2 - 1 230 kV	409	0.74	1.05	0.31	128

Table C-18. PJM Thermal Violations with 50% Offshore Wind Output (HVAC Backbone)—10,212 MW

Overloaded Elements	Contingency	RATING (MVA)	Base Case (pu)	Wind Case (pu)	Diff (pu)	Diff (MVA)
ATLANTIC - LARRABEE - 1F 230 kV	SMITHBRG - NEWPROSP - 1 230 kV	841	0.80	1.04	0.23	195
MANITOU - OYSTER C - 1 230 kV	MANITOU - OYSTER C - 2 230 kV	805	0.99	1.15	0.16	129
MANITOU - OYSTER C - 2 230 kV	MANITOU - OYSTER C - 1 230 kV	805	0.99	1.15	0.16	129
CHICHST1 - EDDYSTN4 - 1 230 kV	FOULK - FOULK8 - 1 230 kV	863	0.99	1.25	0.26	226
CHICHST2 - LINWOOD - 1 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	983	0.76	1.02	0.26	257
CHICHST2 - LINWOOD - 2 230 kV	PEACHBTM - ROCKSPGS - 1 500 kV	983	0.80	1.07	0.27	269
LINWOOD - CLAY_230 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.89	1.17	0.29	233
LINWOOD - EDGEMR 5 - 1 230 kV	CLAY_230 - EDGEMR 5 - 1 230 kV	805	0.96	1.22	0.26	211
CUTHBERT - GLOUCSTR - 1 230 kV	NEW FREE - WINDSOR - 1 500 kV	500	0.86	1.14	0.28	140
CUTHBERT - CAMDEN - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	500	0.79	1.18	0.39	195
THOROFAR - MCKLTON - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	566	0.93	1.10	0.17	94

NWEST326 - CONASTON - 1 230 kV	NWEST311 - CONASTON - 1 230 kV	874	0.93	1.06	0.13	110
GRACETON - BAGLEY - 1 230 kV	CNASTONE - 01KEMPTOWN - 1 500 kV	674	0.68	1.01	0.33	225
CLAY_230 - EDGEMR 5 - 1 230 kV	LINWOOD - EDGEMR 5 - 1 230 kV	805	0.97	1.23	0.26	211
HARMONY - KEEN_230 - 1 230 kV	HARMONY - KEEN_230 - 2 230 kV	739	0.73	1.01	0.28	204
HARMONY - KEEN_230 - 2 230 kV	HARMONY - KEEN_230 - 1 230 kV	739	0.83	1.14	0.31	231
RL_230 - CEDAR CK - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	679	0.15	1.02	0.87	590
COLOR_PE - CECIL - 1 230 kV	CHICHST1 - CHICHST2 - 1 230 kV	179	0.66	1.41	0.75	134
STEELE - MILF_230 - 1 230 kV	MILF_230 - MAGNL230 - 1 230 kV	551	0.21	1.20	0.99	546
STEELE - VIENNA - 1 230 kV	STEELE - VIENNA - 2 230 kV	551	0.88	1.58	0.70	388
STEELE - VIENNA - 2 230 kV	STEELE - VIENNA - 1 230 kV	551	0.88	1.58	0.70	388
COOLSPGS - MILF_230 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.45	1.60	1.14	921
COOLSPGS - INDRIV 4 - 1 230 kV	MILF_230 - INDRIV 4 - 2 230 kV	805	0.60	1.69	1.09	878
COOLSPGS - INDRIV 4 - 1 230 kV	8LDYSMTH - 8POSSUM - 1 500 kV	805		1.09		
MILF_230 - INDRIV 4 - 2 230 kV	COOLSPGS - MILF_230 - 1 230 kV	805	0.49	1.66	1.17	941
MILF_230 - INDRIV 4 - 2 230 kV	8LDYSMTH - 8POSSUM - 1 500 kV	805		1.11		
02S8-ATT - 8 345/138 kV	02AT - 02PERRY - 1 345 kV	370	0.39	1.40	1.01	375
6CHRHLND - 6SEWLSPT - 1 230 kV	6CHRHLND - 6SEWLSPT - 2 230 kV	531	0.76	1.46	0.70	372
6CHRHLND - 6SEWLSPT - 2 230 kV	6CHRHLND - 6SEWLSPT - 1 230 kV	600	0.67	1.29	0.62	373
6FENTRES - 6THRS279 - 1 230 kV	6FENTRES - 6LANDSTN - 1 230 kV	637	0.43	1.07	0.64	409
6SEWLSPT - 1 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	264	0.31	1.16	0.85	226
6SEWLSPT - 2 230/115 kV	6BOWERS - 6CHRHLND - 1 230 kV	264	0.32	1.17	0.86	226
6AYDLETT - 6POINTHB - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	409	0.78	1.04	0.27	108
6POINTHB - 6KITY H2 - 1 230 kV	6KITY H1 - 6SHAWBRO - 1 230 kV	409	0.75	1.07	0.32	132
6KITY H1 - 1 230/115 kV	6KITY H1 - 6KITY H2 - 1 230 kV	203	0.58	1.29	0.72	146
6KITY H1 - 6SHAWBRO - 1 230 kV	6POINTHB - 6KITY H2 - 1 230 kV	409	0.74	1.08	0.34	137

APPENDIX D—PRODUCTION COST ANALYSIS SITE SUMMARY

Table D-1. Selected Offshore Wind Farms in the Atlantic Region

Wind Site						Onshore Interconnection Substation				Delivery System
Site	Capacity MW	Reeds Zone	Region	State	Est COE $/MWh	Name	kV	Dist (km)	GridView Region	
1	698.8	299	Atlantic	SC	206.0	Goose Creek	230	58.9	Carolinas	AC
48	1013.7	293	Atlantic	NC	195.6	Wrightsville Beach	230	63.6	Carolinas	AC
13	987.8	298	Atlantic	SC	197.1	Winyah	230	45.1	Carolinas	AC
14	693.8	298	Atlantic	SC	194.0	Winyah	230	65.5	Carolinas	AC
12	935.8	298	Atlantic	SC	199.5	BUCKSVL	230	48.7	Carolinas	AC
68	407.5	292	Atlantic	NC	204.9	Brunswick	230	35.9	Carolinas	AC
67	1022.5	292	Atlantic	NC	197.0	Brunswick	230	51.9	Carolinas	AC
148	600.3	292	Atlantic	NC	197.4	Brunswick	230	34.8	Carolinas	AC
47	1009.3	293	Atlantic	NC	204.6	Wrightsville Beach	230	22.2	Carolinas	AC
150	911.3	294	Atlantic	NC	191.4	Morehead	230	95.6	Carolinas	DC
21	552.5	349	Atlantic	MA	171.2	Sub 214	345	68.7	ISO-NE	AC
40	890.5	356	Atlantic	ME	197.2	Sub 225	345	57.4	ISO-NE	AC
18	2082.8	342	Atlantic	NY	203.8	Sub 190	345	75.1	ISO-NE	AC
58	498.9	345	Atlantic	RI	204.4	Sub 213	345	77.6	ISO-NE	AC
55	30	345	Atlantic	RI	176.2	Sub 190	345	57.7	ISO-NE	AC
39	561.5	348	Atlantic	MA	202.6	Sub 209	345	65.8	ISO-NE	AC
56	327.5	349	Atlantic	MA	183.3	Sub 214	345	34.1	ISO-NE	AC
57	158.4	356	Atlantic	ME	201.8	Sub 225	345	48.9	ISO-NE	AC
73	351.2	354	Atlantic	NH	193.2	Sub 209	345	15.3	ISO-NE	AC
147	466.1	356	Atlantic	ME	200.3	ORRINGTON	345	102.0	ISO-NE	DC
146	301.7	356	Atlantic	ME	199.9	ORRINGTON	345	86.4	ISO-NE	DC
144	436.4	356	Atlantic	ME	192.6	Main Yankee	345	144.0	ISO-NE	DC
149	544.8	349	Atlantic	MA	199.9	Canal	345	134.1	ISO-NE	DC
10	642.4	349	Atlantic	MA	198.2	Canal	345	118.4	ISO-NE	DC
11	749.1	349	Atlantic	MA	200.0	Canal	345	124.8	ISO-NE	DC
9	592.9	349	Atlantic	MA	199.3	Timber Swamp	345	113.7	ISO-NE	DC
16	**1397.6**	342	Atlantic	NY	206.1	Millstone	345	115.2	ISO-NE	DC
20	1098.3	349	Atlantic	MA	171.5	Canal	345	98.8	ISO-NE	DC
19	427.9	342	Atlantic	NY	204.3	Millstone	345	100.6	ISO-NE	DC
70	887.4	349	Atlantic	MA	204.8	Canal	345	120.5	ISO-NE	DC
71	887.4	349	Atlantic	MA	203.2	Canal	345	80.6	ISO-NE	DC
145	651.5	356	Atlantic	ME	200.1	Newington	345	88.0	ISO-NE	DC
31	977.1	314	Atlantic	VA	201.6	Piney Grove	230	64.0	PJM	AC
30	1014.5	314	Atlantic	VA	196.8	Piney Grove	230	68.8	PJM	AC
32	854.4	314	Atlantic	VA	197.3	Piney Grove	230	77.8	PJM	AC
27	1351.6	315	Atlantic	MD	196.8	Piney Grove	230	53.6	PJM	AC
62	887.7	315	Atlantic	MD	194.2	Indian River	230	49.1	PJM	AC
60	1862.3	330	Atlantic	NJ	185.9	Cardiff	230	51.1	PJM	AC
69	566.8	332	Atlantic	NJ	189.9	Cardiff	230	51.5	PJM	AC
61	467.5	315	Atlantic	MD	194.2	Indian River	230	49.0	PJM	AC
52	816.8	341	Atlantic	NY	194.9	Sub 163	230	29.2	PJM	AC
53	25	332	Atlantic	NJ	194.5	Cardiff	230	23.5	PJM	AC
38	452.6	318	Atlantic	DE	202.6	Sub 151	230	23.9	PJM	AC
63	951.2	307	Atlantic	VA	192.8	Green Run	230	68.1	PJM	AC
43	851.1	330	Atlantic	NJ	186.2	Leisure	230	21.7	PJM	AC
64	1014.5	294	Atlantic	NC	193.0	Kitty Hawk	230	33.5	PJM	AC
66	812.3	294	Atlantic	NC	193.6	Kitty Hawk	230	29.8	PJM	AC
37	1004.6	314	Atlantic	VA	194.7	Piney Grove	230	92.3	PJM	DC
3	**1476.5**	294	Atlantic	NC	189.1	Kitty Hawk	230	81.5	PJM	DC
6	360	294	Atlantic	NC	189.0	Aydlett	230	85.1	PJM	DC
Total	**38564.1**									

Table D-2. Selected Offshore Wind Farms in the Pacific, Gulf, and Great Lakes Regions

Wind Site						Onshore Interconnection Substation				Delivery System
Site	Capacity MW	Reeds Zone	Region	State	Est COE $/MWh	Name		Dist (km)	GridView Region	
5028	412.5	20	Pacific	CA	191.4	Olinda (Vic Fazio)	500	175.4	CALIF_NORTH	DC
5029	706.8	20	Pacific	CA	195.8	Eagle Rock	230	210.3	CALIF_NORTH	DC
5005	561.8	20	Pacific	CA	197.5	Flannigan	230	223.6	CALIF_NORTH	DC
5006	604.2	20	Pacific	CA	198.2	Olinda (Vic Fazio)	500	242.9	CALIF_NORTH	DC
5007	570.6	20	Pacific	CA	207.0	Eagle Rock	230	99.9	CALIF_NORTH	DC
5026	700.4	14	Pacific	OR	192.4	FairView	230	67.1	NWPP	AC
5003	724.1	14	Pacific	OR	205.3	FairView	230	32.7	NWPP	AC
5027	674.6	14	Pacific	OR	195.9	FairView	230	141.4	NWPP	DC
5004	760.4	14	Pacific	OR	199.6	FairView	230	82.2	NWPP	DC
Total	***5715.4***									
1012	300.6	174	Gulf	TX	197.7	NOPALITO	345	73.0	ERCOT	AC
1031	1016.7	174	Gulf	TX	185.3	Rio Hondo	345	52.4	ERCOT	AC
1010	423	174	Gulf	TX	204.8	South Texas	345	42.0	ERCOT	AC
1008	1015	174	Gulf	TX	185.5	Ajo	345	68.2	ERCOT	AC
Total	***2755.3***									
4040	594.5	234	Lakes	OH	199.0	Avon Lake	345	12.7	MISO	AC
4039	939.7	234	Lakes	OH	200.3	Avon Lake	345	23.4	MISO	AC
4045	635.5	234	Lakes	OH	195.9	Ashtabula	345	20.6	MISO	AC
4044	446.9	234	Lakes	OH	194.9	Ashtabula	345	26.4	MISO	AC
4049	797.8	191	Lakes	MI	199.3	Plains	345	73.8	MISO	AC
4047	179.6	191	Lakes	MI	204.4	Dead River	345	75.1	MISO	AC
4042	390.8	234	Lakes	OH	196.1	Ashtabula	345	32.5	MISO	AC
4046	607.2	227	Lakes	OH	205.5	Davis Besse	345	14.0	MISO	AC
4059	395.5	214	Lakes	MI	195.9	Livingstone	345	84.7	MISO	DC
4010	362.7	191	Lakes	MI	203.1	Dead River	345	87.3	MISO	DC
4025	366.6	191	Lakes	MI	203.4	Dead River	345	131.2	MISO	DC
4024	311	191	Lakes	MI	200.7	Dead River	345	104.8	MISO	DC
4043	1063.4	320	Lakes	PA	194.9	Erie South	345	34.1	PJM	AC
Total	**7091.2**									