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The Full Cost of Electricity (FCe-)

Impact of Renewable Generation on Operational Reserves Requirements: When More Could be Less

PART OF A SERIES OF WHITE PAPERS

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THE FULL COST OF ELECTRICITY is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FCe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FCe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy. In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu

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This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

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Impact of Renewable Generation on Operational Reserves Requirements: When More Could be Less

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ABSTRACT

This report presents a qualitative and quantitative description of the impact of renewable generation on the requirements for ancillary services. The fundamental concepts related to ancillary services are presented in the report. First, the need for ancillary services is described, and then the quantification of those needs to satisfy reliability requirements. Then pricing of those services is described. The quantitative part of the report presents an analysis of the impact of nodal protocol revisions as well as installed generation on the procured ancillary services in ERCOT using a statistical approach. This approach allowed correlations to be identified between procured reserves, installed power, and demand. In addition, the approach allowed a ranking of nodal protocol revisions according to their impact on reserves procurements.

LIST OF ACRONYMS

ACE	Area-control error
AS	Ancillary Services
CAISO	California Independent System Operator
CPS	Control Performance Standard
CREZ	Competitive Renewable Energy Zones
DCS	Disturbance Control Standard
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible Alternating Current Transmission Systems
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
NPRR	Nodal Protocols Revision Request
RTO	Regional Transmission Organization
RDD	Regression Discontinuity Design
TSP	Transmission Service Provider

1 | INTRODUCTION

BACKGROUND

The Full Cost of Electricity project aims to understand and explain the cost causation in the whole electricity supply chain. Given the undesired consequences of interrupting electricity supply, reliability considerations play a key role in how electric systems are operated and planned. These reliability considerations are relevant for the full cost of electricity because they may constrain the operation of the power system, increasing its operational costs. This report is focused on short-term reliability considerations, in particular the ones covered by ancillary services.

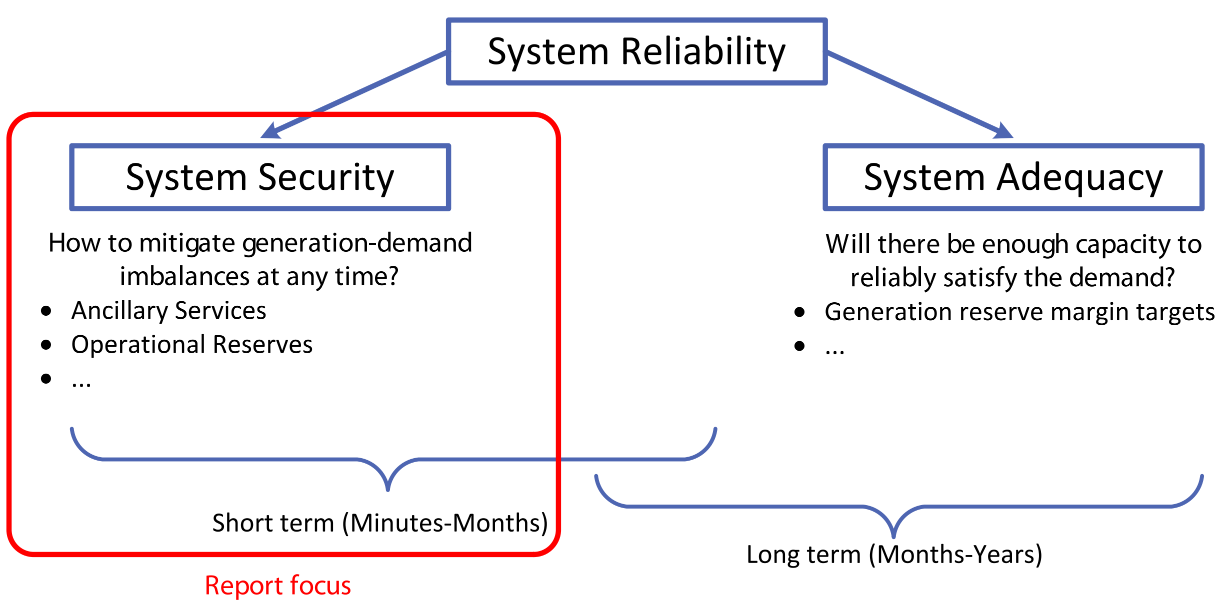
Depending on the time horizon from which reliability is considered, different assumptions can be made about the capability of the system to ensure reliability. Traditionally, in the short term the concern is about being able to support imbalances between generation and demand at all times. The underlying assumption in such analysis is a fixed generation fleet. In particular, operational reserves compensate for increases or decreases in net demand that are not tracked by market or dispatch operations. A more detailed description of them is provided in Chapter 2.

On the other hand, in the long term the concern is whether there is enough installed capacity to satisfy an increasing peak demand, that is, the concern is with so-called resource adequacy. A traditional metric used in this context is the reserve margin, which is the quotient between peak power demand (forecast, in case of forward estimates) divided by the installed power (again, including forecast new resources in case of forward estimates).

Based on the descriptions presented above, the traditional time separation to analyze generation reliability is as presented in Figure 1, which is based on [1]. In the picture it is illustrated that this report is only focused in a part of the system security problem. It is important to keep in mind that some terminology used in the security context might appear in the context of resource adequacy, but with a somewhat or completely different meaning. For example, reserves in the context of operational reserves is something different to reserves for reserve margin.

FIGURE 1

Concepts related to system reliability.



Nowadays there are concerns about the capability to maintain reliability under different disruptive technology changes. One of those changes is the massive development of utility scale renewable generation, whose fluctuating nature is of concern for maintaining security and generation adequacy for power systems. It is important to note that "system security" or "security" in the context of this report are related to maintaining reliable delivery of power to the loads and avoiding disruptions of electricity service to customers. Cyber-Security discussions related to information technology security from computer hacking are certainly important but separate and distinct topics outside the scope of this analysis.

PURPOSE OF THE REPORT

The purpose of this report is to describe and identify the consequences of the development of utility scale renewable generation (principally wind power) for the Electric Reliability Council of Texas (ERCOT). This analysis is only focused on security implications, which is evaluated through the impact of utility scale renewable generation on operational system requirements such as procurements of particular ancillary services.

REPORT SCOPE

The analysis presented in this report has limitations in terms of its capability to predict counterfactual scenarios outside certain study periods. This is because the statistical methodologies used only allow for a meaningful result for predictions confined around a narrow temporal range. Examples of counterfactual scenarios that cannot be explained are the implications had CREZ not been developed and the possible massive development of solar power in West Texas. A second issue is about the meaning of the results obtained. From the regression models constructed, it was possible to identify significant correlations between variables such as installed generation, demand, and operational reserves. However, no conclusions about causation can be inferred from these results alone. A third issue is the quality of the data used. For some data sets, it is possible to use finer time resolution, which might eventually improve the quality of the results obtained. For example, the updates in installed power can be performed with monthly resolution rather than the annual data used in this analysis.

REPORT STRUCTURE

The main content of this report is about ancillary services, which is covered in Chapter 2. It starts by explaining the needs for providing ancillary services. Then the concept of operational reserves, and the different types of reserves, is presented. After describing the concepts, the methodology for calculating requirements for operational reserves is described, with a particular emphasis on the case of ERCOT. Next is presented a brief discussion about the capability to provide ancillary services, continuing with how a market oriented approach can assign a price to a reserve. Chapter 3 presents the results obtained from the analysis of historical procured ancillary services. This analysis is focused on the identification of the effect on procured quantities of reserves due to the changes in protocols that define them, as well as due to the capacity of installed wind power. The details about the calculations performed are presented in an appendix at the end of the document. Finally, conclusions for the overall report are presented in Chapter 4. ■

2 | ANCILLARY SERVICES DESCRIPTION

BACKGROUND

Secure operation of a power system means that no component should function outside its safe operating range even in the event of disturbances [2]. For example, it is required that system electric frequency remains in very narrow ranges, despite variation in supply and demand, because of generator design characteristics. Another example is the maintaining of voltage levels across the transmission network, fulfilling the requirement of maintaining load voltages within a narrow range to avoid damage to equipment, among other issues.

In principle, security could be maintained through interruption of loads. However, it is generally accepted that consequences of interrupting the electricity supply to loads have significant consequences, which justifies the need for provisions in the system to maintain security without significant resort to load interruptions even despite disturbances, such as failures of generators or, in recent years, significant changes in renewable production.

Based on the above ideas, and the ongoing market restructuring in U.S. in the 90's, the Federal Energy Regulatory Commission (FERC) defined in its Order 888 ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system" [3]. Traditionally, ancillary services have been provided by generators, but they can be provided by other types of technologies such as transmission equipment and load. Ancillary services as defined by FERC, and their respective time scales are presented in Table 1.

Scheduling, System Control, and Dispatch are tasks that an Independent System Operator (ISO) or Regional Transmission Organization (RTO) has to perform. It includes the schedule of generating units, transmission resources, and transactions before the fact and the monitoring and control of transmission resources and generation units in real-time to maintain reliability.

Reactive supply and voltage control is the capability to provide the resources required in the system to keep the voltage at certain locations within desired ranges. The transference of real power in an alternating current network requires the establishment and sustainment of electric and magnetic fields. An abstraction used to represent this requirement is the so-called reactive power, which has direct implications on the voltage in the network. Generators can absorb or inject reactive power to maintain voltage levels within normal ranges. However, this action limits the capability to inject real power into the network. Therefore, it is a service that has an opportunity cost associated. Moreover, the impact of voltage regulation has a more local effect than system

TABLE 1

Ancillary services defined by FERC and their associated time scales [4].

Service	Time scale
Scheduling, System Control and Dispatch	Seconds to hours
Reactive supply and voltage control	Seconds
Regulation and frequency response	~ 1 minute
Energy imbalance	Hourly
Operational reserves – Synchronized reserve	Seconds to < 10 minutes
Operational reserves - Supplemental reserves	> 10 minutes

wide, therefore, there are few opportunities for system-wide procurement of reactive power.

The regulation and frequency service is the capacity to take corrective actions to balance mismatches between generation and demand. Under the normal operation of power systems, these imbalances commonly happen because of reasonable and inevitable forecasting errors, the sudden failure of generators, lines, and load disconnections. As a consequence of these imbalances, the system frequency drops or increases. This change in frequency may be harmful for some elements in the system. The above justifies the need for a service to help regulate frequency, by controlling short-term production of resources to restore frequency towards its nominal value.

Energy imbalance is a service provided by transmission service providers (TSPs) associated with the discrepancy between scheduled and actual delivery of energy to a load located in a control area. In RTO and ISO markets it is provided by the resources procured in the real-time market.

Synchronized reserves (called responsive reserve in ERCOT) is the use of generating equipment and interruptible load that can essentially immediately respond to changes in frequency and that can be dispatched to correct for generation/load imbalances, typically with a requirement that it is fully available within 10 minutes. Supplemental reserve is the use of generating equipment and interruptible load that can be fully available within a somewhat longer period to correct for generation/load imbalances caused by generation or transmission outages. Supplemental reserve differs from spinning reserve primarily in that supplemental reserve need not begin responding to an outage immediately. This service involves the provision of additional generating capacity that can commence after 10 minutes but must be fully operational within thirty to sixty minutes.

It is important to notice that these FERC Order 888 definitions were promulgated in 1996, a time prior to the massive development of utility scale renewable generation. However, as is pointed out in [5], these definitions are still useful to some extent. However, the radical change due to much greater levels of intermittent renewables has required a revisiting of the impact on ancillary services, in particular those related with operational reserves. Therefore, the rest of the report is focused on operating reserves: its definitions and classifications, requirements, and provision. The next section describes operational reserves in more detail.

OPERATIONAL RESERVES

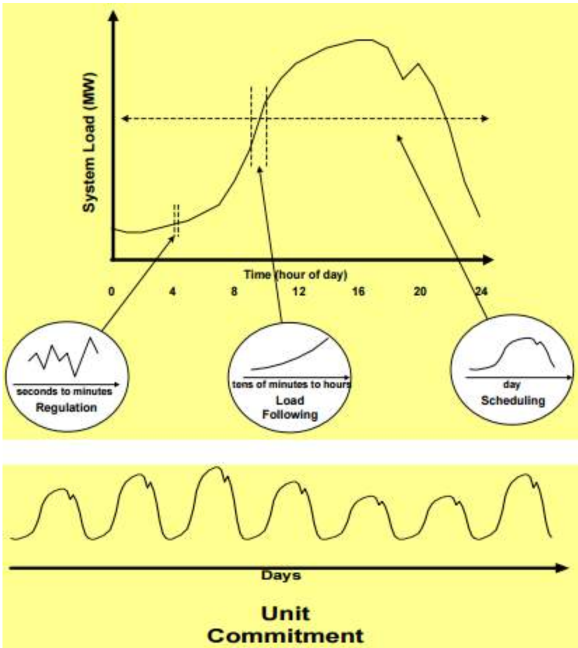
The balance between generation and demand has to be maintained at all times due to the lack of cost-effective massive-scale grid storage at the timescales required. To do so, different strategies are used for different timescales, which are illustrated in Figure 2. Forward scheduling of the power system includes schedules and unit commitment directions to meet the general load pattern of the day. Load following is the action to follow the general trending load pattern within the day. This is usually performed by economic dispatch and sometimes involves the starting and stopping of quick-start combustion turbines or hydro facilities. Regulation is the balancing of fast second-to-second and minute-to-minute random variations in load or generation. This is done by centralized control centers sending out control signals to generating units (and some responsive loads) that have the capability to rapidly adjust their dispatch set points. These strategies represent the balancing during normal conditions of the power system.

The above description does not consider sudden demand-generation imbalance perturbations which naturally happen during the operation of power systems, typically due to the failure of a generator. The existence of these imbalances justify the need for additional operational reserves besides the regulating reserves described above. These reserves stabilize system frequency within a prescribed amount of time, and subsequent actions restore the system to being secure with respect to another failure.

The supply-demand imbalances can be related to the presence or not of an event in the system. Events include severe and rare occurrences, but in addition there are effectively continuous changes in

FIGURE 2

Power system operation time-frames [6].



supply-demand due to the addition of a large number of individual consumption changes, which we will refer to as "non-event considerations." This separation between event and non-event considerations has been used to categorize different types of operational reserves commonly used in different systems interconnections. Based on this, [6] created the classification presented in Figure 3, which will be used in this report. It is important to mention that there is no a single classification for operational reserves, however the classification selected here is general enough to explain most of the issues involved in operation reserves. Later on, the equivalent ERCOT reserves will be associated with this description.

Regulating reserves covers the continuous fast and frequent changes in load and generation that create energy imbalance resulting in changes in system frequency. It is the finest scale of balancing done during normal conditions. It is used to correct the current imbalance caused by load or generation variation within the shortest applicable market or economic dispatch interval, and correct short-term load and renewable forecast errors. In some areas, the shortest scheduling interval may be up to an hour and in others this interval may be as short as 5 minutes. What this means is that if the system operator dispatched units thinking the net load was moving in a certain direction, and the magnitude or direction is different than anticipated, the Regulating Reserve must be used to help correct the discrepancy until the next economic dispatch cycle can update. Required Regulating Reserves would tend to increase with increasing forecast error in the short-term wind forecast.

Following Reserve is analogous to Regulating Reserve, but on a slower time scale. It is needed to accommodate the variability and uncertainty that

FIGURE 3

Illustration of concepts involved in categorization of operating reserves [6].

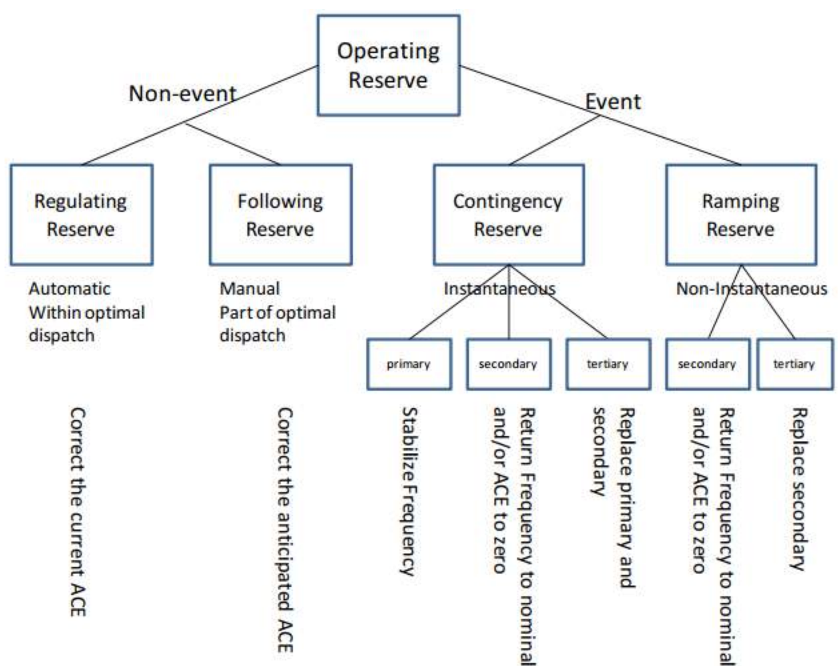
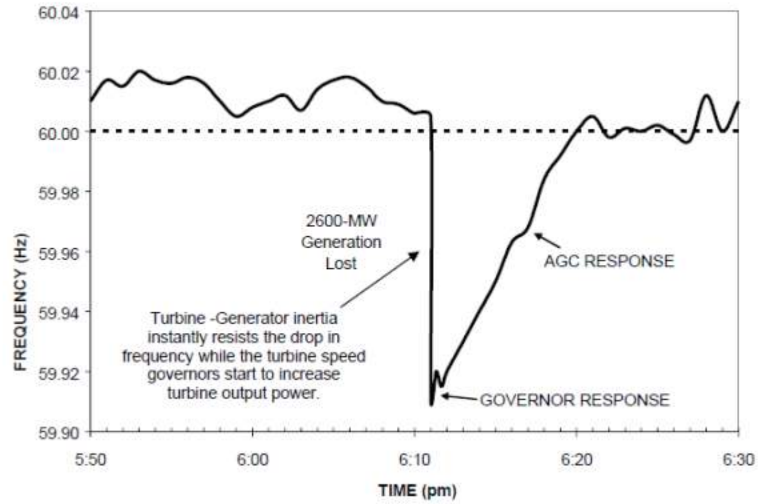


FIGURE 4

Example contingency (loss of supply) event and typical responses [6].



occur during normal conditions. The definition used in [6] represents the movements that are reflected in the economic dispatch to correct an imbalance that is forecast to occur in the future. Issues that impact the need for Following Reserve are much less random than those for Regulating Reserve, but larger in magnitude than Regulating Reserve. Following reserve covers both typical load and variable generation patterns and inter-schedule interval variability. In the case of ERCOT, the load and generation short-term trend forecasts are covered by real-time economic dispatch. On the other hand, the 95% of the remaining generation and load uncertainty is covered by Regulation-up, Regulation-down, and Non-spinning reserve. In addition, Non-spinning reserve can be used for loss of generating units. The requirement for participation in providing this service is to be either on-line (for Regulation-up and Regulation-down) or off-line (for Non-Spinning Reserve), with full response required within thirty minutes [6].

Unlike Regulating and Following Reserves, Contingency Reserves are called upon during rare sudden events. The events usually considered are a large sudden loss of supply either from generating resources or large transmission lines carrying imports, but more generally can consider loss of large blocks of load as well. Contingencies occur quickly and much of the reserves must start acting essentially immediately. Figure 4 presents a typical response to a sudden loss of a large generating unit. Immediately following the event, the generator rotating masses will supply kinetic energy, partly mitigating the generation-demand imbalance. As a consequence, system frequency experiences changes due to deceleration of generator rotors. It is important to mention that there are current advances in power electronics that allow non-synchronous generators (e.g. wind and solar power) to provide synthetic inertial response [7].

Ramping reserve is probably the least well defined category of the list presented by [6] and is only explicitly procured currently in some markets, such as flexi-ramp in CAISO (California Independent System Operator) [8]. This type of reserve is used for rare severe events that are not instantaneous in nature. Large load variations occur every day, are predictable, and are met with Following Reserve and the action of the energy markets rather than Ramping Reserve. Due to the greater unpredictability of wind and solar, infrequent large magnitude events may occur that require additional Operating Reserves. The separation between Following Reserves and Ramping Reserves is that the first may cover most of the possible deviations, and ramping reserves the remaining.

Primary reserves correspond to a certain portion of contingency reserves that must be automatically responsive to changes in frequency. Primary reserve is needed to stop frequency deviations from becoming too large. This protects generators from excessive frequency deviations which can create conditions that may cause damage to the generators

TABLE 2

Similarities between concepts in [6] and ERCOT.

Ela, Milligan, and Kirby AS definition	ERCOT similarities
Regulating reserves	Regulation-up and regulation-down
Following Reserve	Real-time dispatch, and Non-spinning reserve
Contingency reserve – Primary	Responsive reserve

or set off under-or over-frequency relays which can shed system load or disconnect generators, which would further worsen the effect of the contingency. Secondary reserve including both Contingency Reserve and Ramping Reserve are used to return the frequency back to its nominal value and reduce ACE (Area Control Error) back to zero. Tertiary reserve is unique because it is the only reserve category that is not deployed for energy imbalance, but is instead deployed for reserve insufficiency. In other words, it is held in some manner so that when certain operating reserve types are used to correct the energy imbalance and converted into energy, it is used to restore that form of Operating Reserve. Tertiary Reserves do not need to be as fast as the secondary reserves, and are used to allow the system to recover reserves by introducing new economic generation.

Based on the previous review of reserves, and the definitions for ERCOT reserves provided in [9], Table 2 presents some similarities between the definitions of operational reserves used in this chapter, and the current ERCOT reserves recognized. The way in which these reserves are determined will be described in the next section.

QUANTIFICATION OF OPERATIONAL RESERVES REQUIREMENTS

Ancillary services requirements that ISOs and RTOs procure in their markets are directed by reliability requirements, which vary among different interconnections. In North America, the reliability requirements are specified by North American Electric Reliability Corporation (NERC). Based on these requirements, and the variances associated to demand and renewable generation, procured operational reserves are determined to ensure certain reliability performance indices satisfy required specifications. Some of the specifications are statistical. However, for certain types of reserves, such as contingency reserves, deterministic reserves requirements based on conservative considerations (such as the largest creditable generation contingency) have been traditionally used, although it is also possible to define them economically based on probabilistic terms [10].

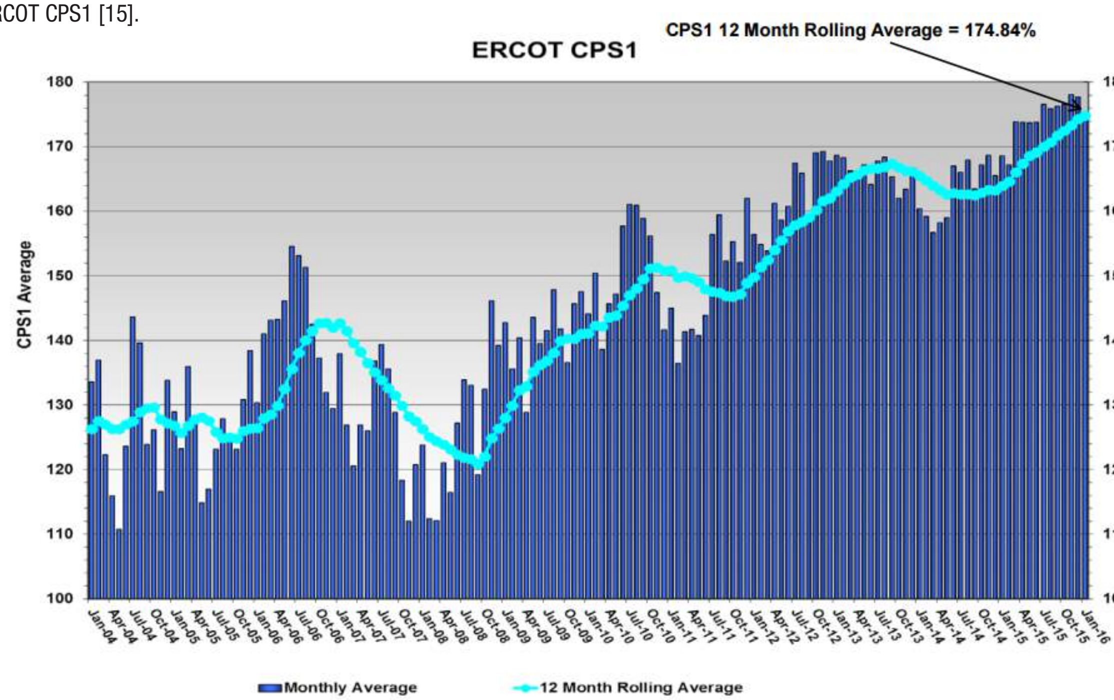
Examples of the application of these reliability requirements in the quantification of operational reserves requirements can be found in the Eastern Wind Integration and Transmission study [11], and in Western wind and solar integration study [12], which determine different operational reserve requirements in terms of renewable generation production, demands, as well as the variances associated to them, among other things. In this section, the requirements in ERCOT for each operational reserve are described.

REQUIREMENTS FOR REGULATING RESERVES IN ERCOT

For the purpose of regulating reserves NERC established the NERC standard BAL-005 [13] which states that “Each balancing authority shall maintain regulating reserve that can be controlled by automatic generation controllers to meet the Control Performance Standard (CPS),” where the metric CPS is in terms of the frequency excursion under and above the system frequency. This means that each ISO/RTO has to find a way to define its operational reserves in such way to fulfill CPS criteria. In the case of ERCOT, which is a single balancing authority, it has to fulfill that its CPS1 is greater than 100%. (The maximum possible value is 200%). As can be seen in Figure 5, ERCOT has easily fulfilled this standard. In order to procure

FIGURE 5

Historical ERCOT CPS1 [15].



regulation, ERCOT splits the regulation into regulation-up and regulation-down. The amount of reserves procured are based on 98.9th percentile of regulation reserve utilized in previous 30 days and on the same percentile of regulation utilized in the previous year and adjusted by installed wind penetrations, as discussed below. This requirement is differentiated on an hourly basis.

To adjust the amount of Ancillary Services procured by installed wind penetration, ERCOT calculates the increased amount of wind capacity compared to the previous months and uses a look-up table to add increased amounts of regulation based on a study performed for the region [14]. In addition, if during the course of the past 30 days, the average CPS1 score was less than the 100% target, an additional 10% of regulation will be procured during those hours where it was less than 100%. If the CPS1 score was less than 90%, an additional 20% of regulation service will be added [6], [9].

FIGURE 7

Historical procured regulation-up reserves in ERCOT.

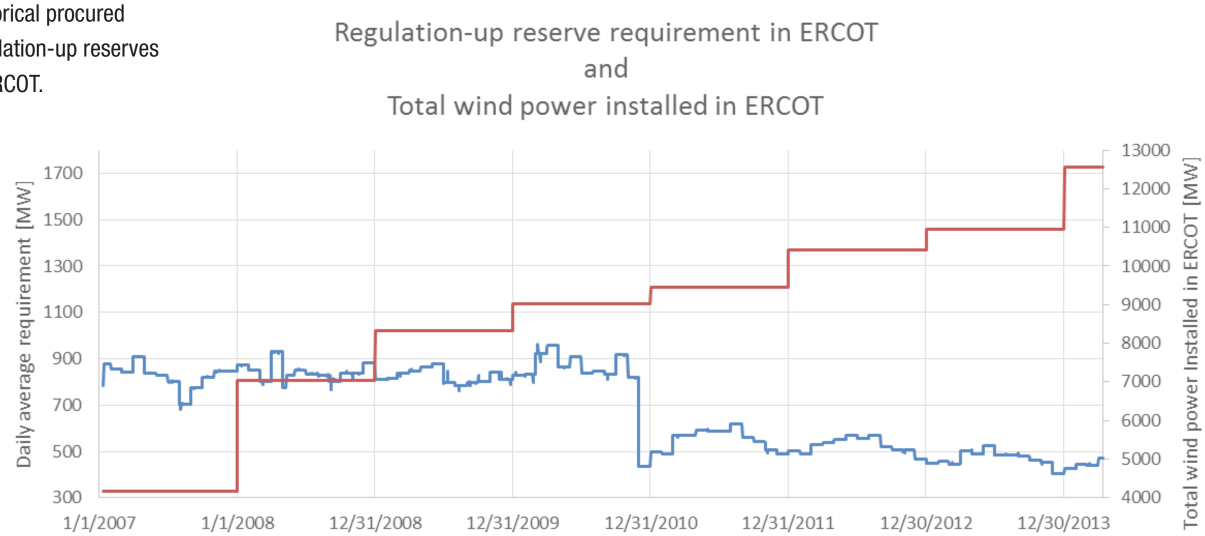
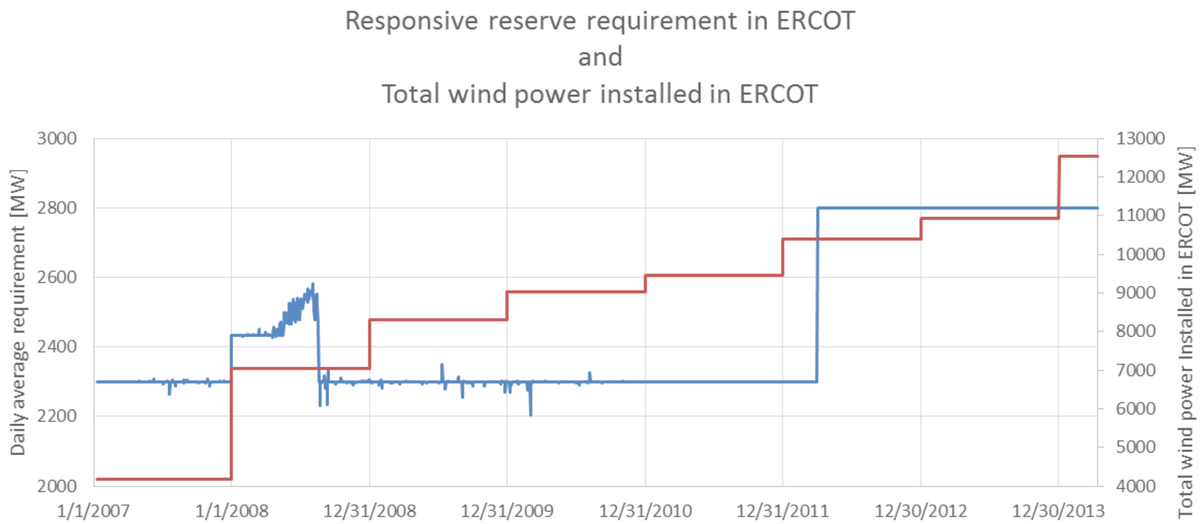


FIGURE 8

Historical procured responsive reserve in ERCOT.



As a result of these correction mechanisms, CPS1 compliance has been maintained over time. The consequence of that compliance can be seen in the change over time of the procured regulation-up and regulation-down as presented in Figure 6 and Figure 7, respectively.

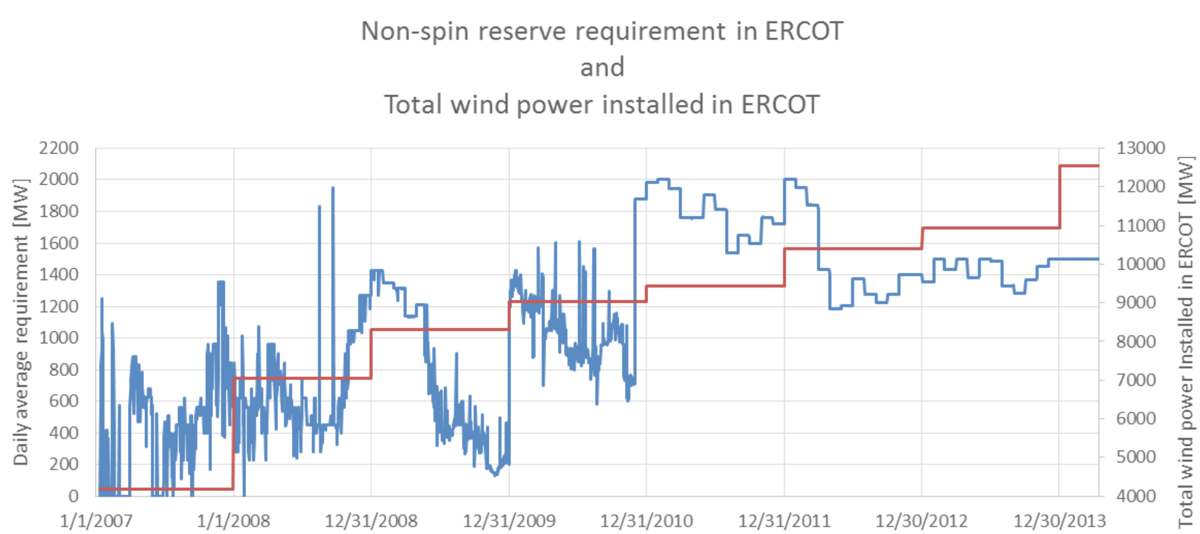
From both figures it can be appreciated that there have been changes over time for these quantifies, with CPS1 scores generally improving, while regulation procurement quantities have remained approximately static or reduced, despite significant increases in the installed wind capacity.

REQUIREMENTS FOR RESPONSIVE AND NON-SPINNING RESERVES

In the same way as for regulating reserves, NERC Disturbance Control Standard (DCS) Standard BAL-002 [16] establishes that "as a minimum, the balancing authority or reserve sharing groups shall carry at least enough contingency reserve to cover the most severe single contingency". In the case of ERCOT, the contingency reserve considered have been the trip of nuclear generation units for at least 2300 MW as can

FIGURE 9

Historical procured non-spinning reserve in ERCOT.



be seen in Figure 8. However, based on the conclusions of a study performed for ERCOT [14], an additional 500 MW of responsive reserves was added to the requirement in order to ensure that reserve regulation, responsive reserve, and non-spinning reserve have a capacity to respond to the 95% of the uncertainty in the net load. [9]. This underpins the increase in responsive reserve requirement from 2300 MW to 2800 MW in 2012, and the corresponding decrease in non-spinning reserve requirement.

Regarding Non-Spinning Reserves, historically the need for it has occurred during hot weather, during cold weather, during unexpected changes in weather, or during large unit trips when large amounts of spinning reserve have not been on line. That can explain in part the sudden changes that can be seen for the procurement of this reserve in Figure 9 [9].

ERCOT FUTURE NEEDS FOR ANCILLARY SERVICES

Finally, it has to be mentioned that the massive development of utility scale non-synchronous generation (e.g. wind power) has raised concerns about the capability of the system to maintain security. In particular, the replacement of synchronous generation by non-synchronous generation may produce significant reduction in system inertia, which makes it less resilient to contingencies. In order to overcome this situation, ERCOT has proposed an unbundling of ancillary services associated with frequency regulation, in order to incentivize market participants to provide inertia (instead of being a compulsory service like it is nowadays) [17]. According to the reference, the implementation of these future ancillary services has a benefit cost ratio of 10.

PROVISION OF ANCILLARY SERVICES

Once the requirement of ancillary services is identified, a way is needed to procure it. First, the technical capability to provide the service must be identified, and second is the need for a mechanism to compulsorily or voluntarily obtain these requirements. Traditionally, ancillary services have been provided to a great extent by conventional generators (e.g. thermal and hydro units), and to a lesser extent by other devices such as capacitor banks, FACTS, synchronous motors, etc. Nowadays, there are more technical alternatives such as non-traditional generation ancillary services, demand response, and energy storage.

COMPULSORY PROVISION OF ANCILLARY SERVICES

This way to provide ancillary service is the closest to the vertical integration case. Typically, for a new generator to enter into the power system, it is required to provide certain types of ancillary service. A typical example in North America is the contribution of primary frequency response.

In [2] several reasons are given for why this is not necessarily a good economic policy:

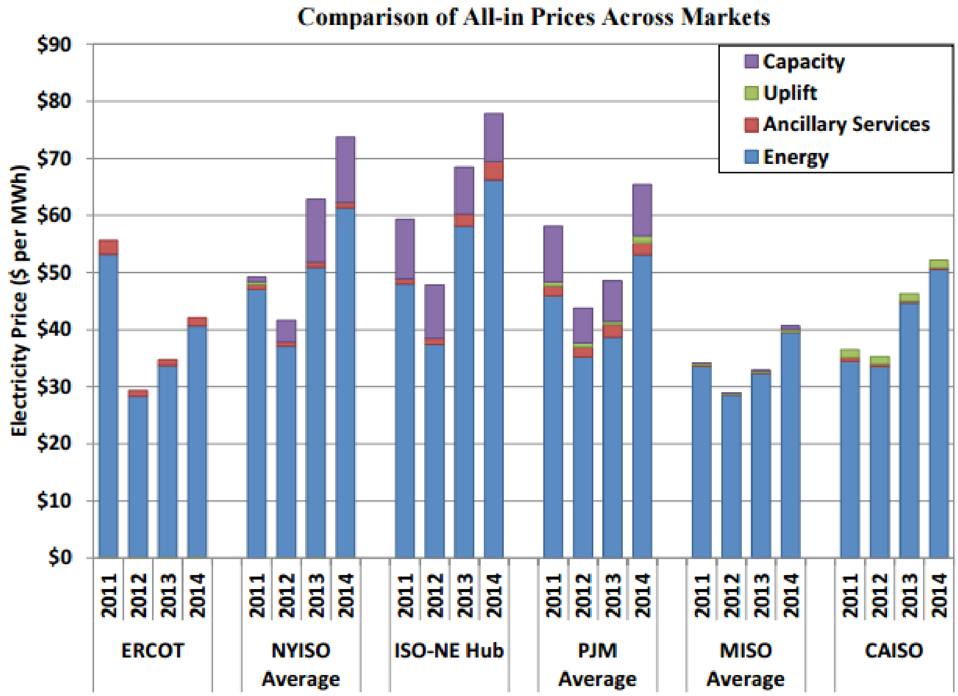
- It may cause unnecessary investments compared to what is needed. For example, not all generating units need to take part in frequency control to maintain the security of the system.
- It does not give room for technological or commercial innovation because there is no differentiation amongst provision.
- It generates a negative perception among providers because they feel that they are forced to supply a service that adds to their costs without being remunerated.

MARKET ORIENTED PROVISION OF ANCILLARY SERVICES

The individual ancillary services differ substantially in their features, competitiveness, provision, and pricing. Operating reserves, for example, can likely be provided by competitive markets. The primary supplier cost for this service is the opportunity cost associated with foregone energy sales; significant fuel costs are incurred only when these reserves are called upon to respond to the loss of a major generation transmission outage.

Injection and absorption of reactive power, on the other hand, must be provided close to the location where the voltage control is needed.

FIGURE 10



Comparison of all-in Prices across U.S. Markets [19].

Therefore, it may not be feasible to create competitive markets for this service. Rather, the pricing and provision of voltage control may continue to be regulated. Capital costs are the dominant costs for this service for both generators and transmission equipment. Opportunity costs arise only when generators are operating at or near full real-power output and are called upon to increase reactive-power output beyond the level associated with the unit's rated power factor. [4]

In a market oriented approach to provide ancillary services, market participants make offers to provide their services, which are cleared by obtaining a price for these services. Figure 10 shows the prices paid for different electricity product across different interconnections in U.S. from 2011 to 2014. It can be appreciated that the price associated with ancillary services is small in comparison with energy prices. In particular, average ERCOT ancillary services price represents in average between 3% and 4% of the annual energy prices.

There are different ways to obtain a price for ancillary services. In early years of competitive electricity markets, energy and each type of operational reserve were treated in separated markets. These markets were cleared successively in a sequence determined by the speed of the reserves required. The experiences obtained from this approach were unsatisfactory in terms of efficient price formation for reserves. For example, it is expected that there should be a higher price for a faster response, which was not the case in this original approach [18]. From these experiences, the now commonly used co-optimization approach for valuation of ancillary services and energy was developed. Co-optimization is used in ERCOT.

CO-OPTIMIZED PROVISION OF ENERGY AND RESERVES IN A CENTRALIZED ELECTRICITY MARKET[1]

In a co-optimized energy and reserves markets, the price of the ancillary services is obtained as Lagrange multipliers on the reserve demand constraints, in an economic dispatch.

To fix ideas, consider a power system with four generators, in which the transmission network is neglected like the one presented in Figure 11. Table 3 presents the parameters of the generators. In this system only the requirements of spinning reserves and energy will be considered.

1 The example presented here was extracted and paraphrased from [2].

FIGURE 11

System used to illustrate the co-optimization of energy and ancillary services.

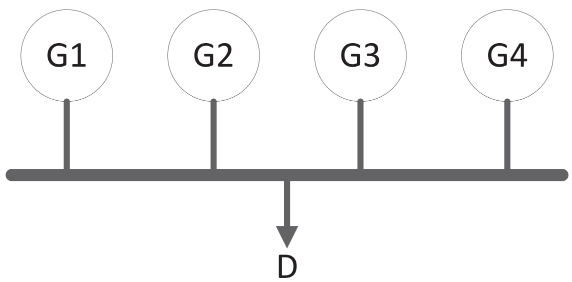
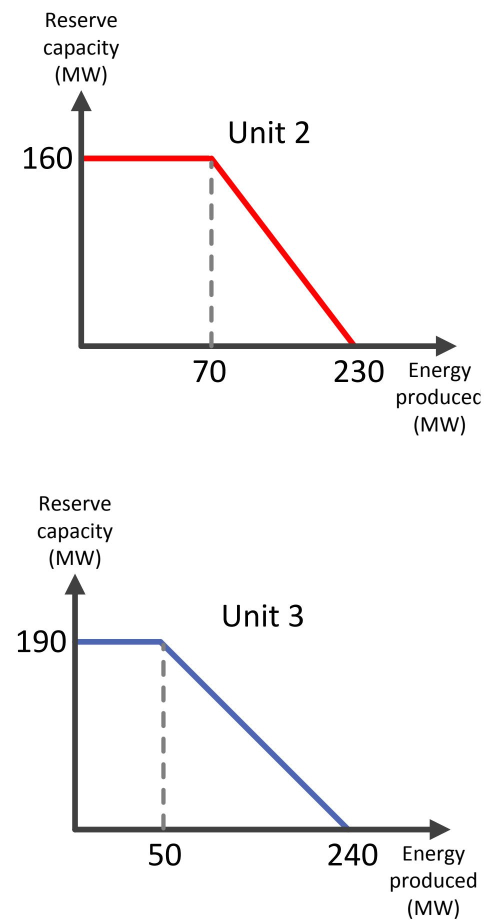


FIGURE 12

Amount of reserves that generating units 2 and 3 can provide as a function of the amount of electrical energy production.



Notice in this example that some generators cannot provide reserves. A reason for this could be that they are so slow to change generation as to be considered incapable of providing reserves, or that they simply don't want to provide them into the market for strategic reasons. Another important issue is that although a generator might be willing to offer up to certain amount of reserves, the generation unit capacity limits the total amount of reserves plus generation of energy at every time. This situation is illustrated in Figure 12, where generation units 2 and 3 are limited in the amount of reserves they can provide, for a given generation level.

In this example, we seek the generation levels for the four generators that minimize the total generation cost, assuming that they are already committed to generate. This objective is expressed in (1). This problem is called economic dispatch. Notice that it is a different problem than the unit commitment problem, in which apart from the generation levels of generators, the commitment status is also considered. Also notice that non-spinning reserves don't have a cost by themselves given a generator is not consuming fuel to produce them. Regulation up or down reserves fuel consumption increases and decreases fuel consumption such that the net fuel consumption difference is assumed to be near zero. Responsive reserves (spinning reserves) do require thermal generations to be synchronously on-line and consume some modest amount of fuel.

The demand balance is presented in equation (2). Notice that this balance doesn't correspond necessarily to the real conditions that might occur

TABLE 3

Generators data for illustrative system.

Generating unit	Marginal cost of energy [$/MWh]	Pmax [MW]	Rmax [MW]
1	2	250	0
2	17	230	160
3	20	240	190
4	28	250	0

in the system at any time. But it is a reference for the production of the generators. Moreover, it is used for pricing purposes. The energy prices correspond to the Lagrange multiplier associated to this equation. Equation (3) represents the requirement for reserves for the whole system. It can be appreciated that it is possible to have more reserves than those required, and so the constraint is represented as an inequality. The price associated to these reserves will be obtained from the Lagrange multiplier associated to this equation. Finally, in equations (4), (5), and (6), are presented the bounds for generation and reserves.

(1)

$$Z = \min_{P_1, P_2} 2P_1 + 17\,P_2 + 20P_3 + 28P_4$$

(2)

$$P_1 + P_2 + P_3 + P_4 = D$$

(3)

$$R_1 + R_2 + R_3 + R_4 \geq 250$$

(4)

$$\begin{gathered} 0 \leq P_1 \leq 250 \\ 0 \leq P_2 \leq 230 \\ 0 \leq P_3 \leq 240 \\ 0 \leq P_4 \leq 250 \end{gathered}$$

(5)

$$\begin{gathered} R_1 = 0 \\ 0 \leq R_2 \leq 160 \\ 0 \leq R_3 \leq 190 \\ R_4 = 0 \end{gathered}$$

(6)

$$\begin{gathered} P_1 + R_1 \leq 250 \\ P_2 + R_2 \leq 230 \\ P_3 + R_3 \leq 240 \\ P_4 + R_4 \leq 250 \end{gathered}$$

TABLE 4

Solution of the optimization problem for different demand levels.

Demand [MW]	P_1 [MW]	R_1 [MW]	P_2 [MW]	R_2 [MW]	P_3 [MW]	R_3 [MW]	P_4 [MW]	R_4 [MW]
300-420	250	0	50-170	60	0	190	0	0
420-470	250	0	170	60	0-50	190	0	0
470-720	250	0	170	60	50	190	0-250	0

In Table 4 are presented solutions for different demand levels. The checking of the results by hand provides insights about how ancillary services are priced under a co-optimization approach. A simplified approach to obtain the prices for energy and ancillary services is to ask what would be the overall increase in the operating cost of the system if an infinitesimal increase in demand or reserves requirements were to occur.

For a demand level between 300 to 420 MW, it is clear that generator 1 has to operate at full load because it is the cheapest and it cannot provide reserves. The next cheapest generator is generator 2, which can provide energy and reserves. Notice that it is most economical to generate as much of the remaining required energy as possible with this generator, or in other terms, for it to provide reserves as little as possible. However, the other generator that can provide reserves, generator 3, does not have enough capacity to supply the full requirement of 250 MW of reserves (it only can provide up to 190 MW of reserves). Therefore, the minimum amount of reserves that generator 2 has to provide is 60 MW. Thus, generator 2 has to provide the remaining energy. On the other hand, generator 3 has to provide as much reserves as possible, because in this way generator 2 can generate cheaper energy. Under this demand scenario, maintaining the amount of reserves required, an additional unit of energy would be provided by generator 2 at a cost of $17. Furthermore, maintaining the energy demand, if an additional unit of reserves has to be provided, only generator 2 can provide it. Given that in this range generator 2 is not limited in its production, the provision of an additional unit of reserves doesn't incur in any additional system cost.

For a demand range between 420 to 470 MW, generator 2 has to produce as much energy as possible. However, this is not enough to satisfy the demand. Therefore, the next generator in cost, generator 3 has to provide the remaining energy. Under this scenario, and maintaining the requirement of reserves, an additional energy unit has to be provided by generator 3 at a cost of $20. Regarding an additional unit of reserves, maintaining the energy production, it is clear that only generator 2 can provide it. In order to do that, it is required to reduce its energy production by one unit, increase the reserves production in one unit, and cover the remaining demand with generator 3. So in this exercise the overall operation cost is increased by $20 and decreased by $17, which means that the cost of an additional reserve unit is $3.

Finally, in the case when the demand is between 470 MW and 720 MW, the energy production of generator 3 is not enough and generator 4 has to contribute with energy. The reserves requirements can be satisfied by generator 2 and generator 3.

To summarize, in a co-optimized market, the price of the reserves is set by the opportunity cost of foregone energy sales, as described in the above paragraphs, or in some cases by a non-zero offer cost of reserves. ■

3 | RESULTS OF IMPACT ANALYSIS

This chapter describes the results obtained for the analysis of procured ancillary services in ERCOT between 01/01/2007 to 04/13/2014. The purpose of the analysis is to obtain the impact significance of changes in nodal protocols revisions as well as changes in installed generation. The analysis started with a preliminary list of nodal protocol revisions related with wind power. The verification of the significance was performed by a simplified statistical approach using Regression Discontinuity Design rather than a direct calculation method, which allowed significant reductions in the amount of calculations involved. The details of this analysis are presented in the appendix of the report. From the above analysis the following results were obtained:

- There are significant correlations between the procured regulation-up and regulation-down and the daily maximum demand, daily minimum demand, and installed wind power, and the associated coefficients are presented in Tables Table 10 to Table 18. In several cases it was found that non-coastal and thermal generation installed power were positively correlated with procured regulation-up and regulation-down reserves. However, for the zonal market period, it was found that installed wind coastal generation has a negative correlation.
- There are significant correlations with past procured reserves, which is due to the self-corrective action considered based on past operation performed by ERCOT.
- Regarding network protocol revisions purely associated to wind power, it was found that the following ones were significant:
    - NPRR 352 (6/1/2011):
        - Improvements in prediction of the maximum sustained energy production after curtailment.
    - NPRR 361 (9/1/2011):
        - Requires submission of 5 min resolution wind data for real time purposes.
    - NPRR 460 (12/1/2012):
        - Increases the wind powered generation resource ramp rate limitation from 10% per minute of nameplate rating to five minute average of 20% per minute of nameplate rating with no individual minute exceeding 25%.
- Finally from Table 19, Table 20, and Table 21, it was found that the most significant impact was made during the introduction of the nodal market, which are compared against the other protocol revisions in Figure 13 and Figure 14. In particular, the change from 15-minutes to 5-minutes dispatch intervals was a dramatic change [20]. The reason for this is that as the dispatch time is reduced, the action of the real-time market can more quickly take corrective actions for the perturbations in the demand-generation balance. Therefore, less reserves are required to cope with the reduced uncertainty in net load over the shorter dispatch interval used in the nodal market. This result is in accordance with the recommendations to increase renewable penetration in the Western Interconnection [21]. In addition, it was observed that the least significant protocol revision was NPRR352, which was related with the wind forecasting improvements.

FIGURE 13

Impact of protocols revisions on Regulation-up reserve requirements.

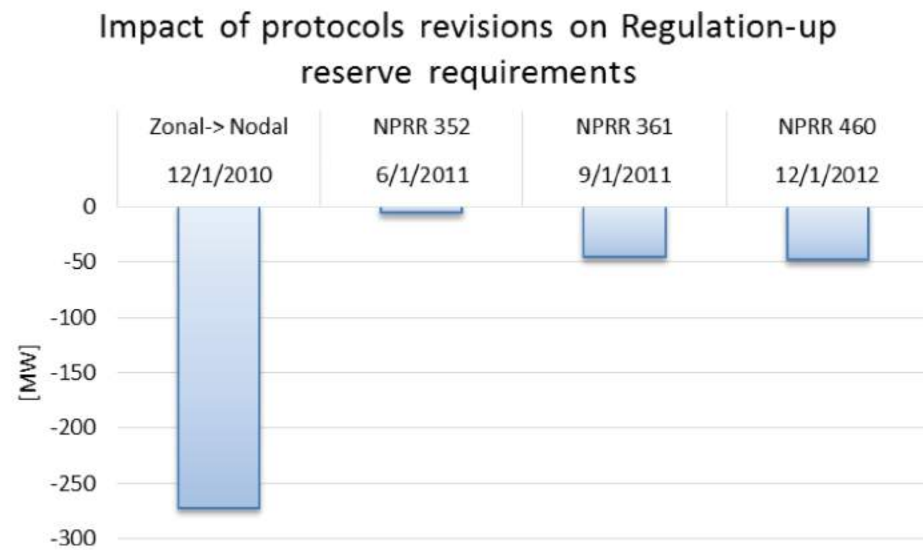
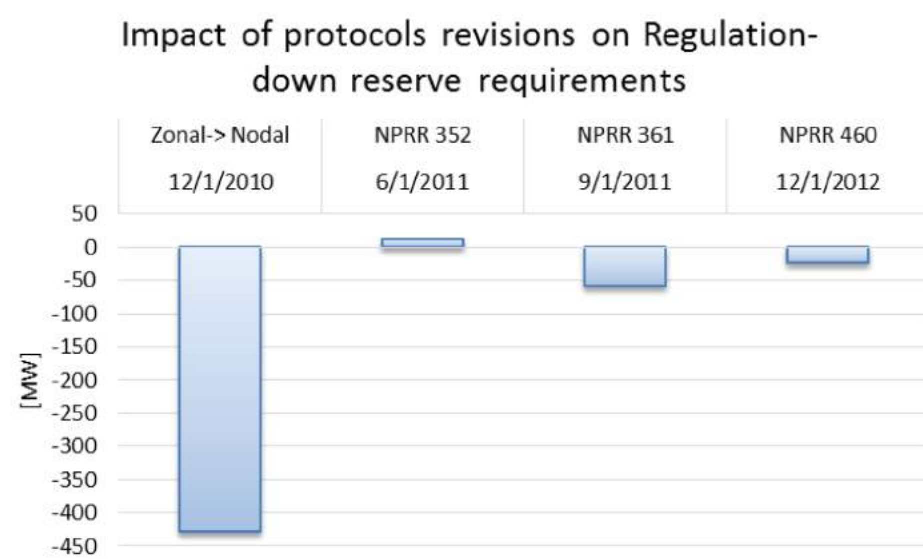


FIGURE 14

Impact of protocols revisions on Regulation-down reserve requirements.



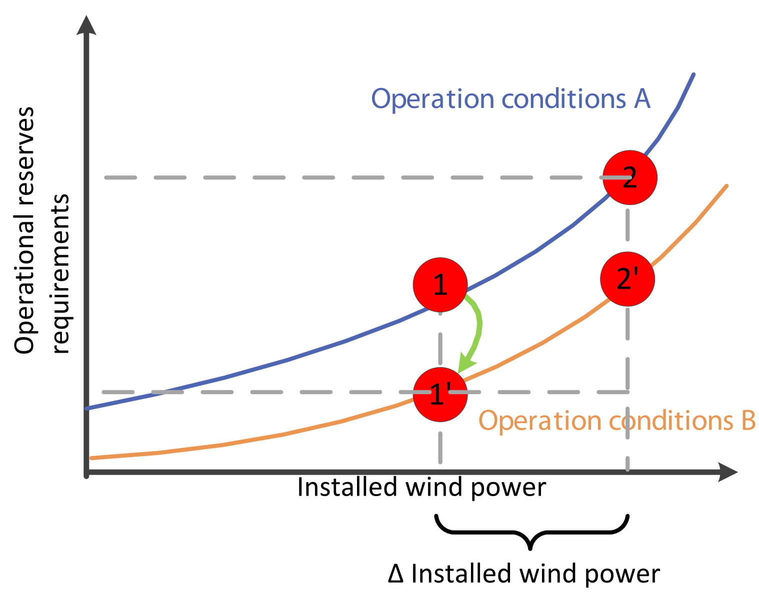
4 | CONCLUSIONS

This report has described the need, identification, and valuation for ancillary services, with emphasis on ERCOT. A statistical analysis of the procured quantities of ancillary services was analyzed in the context of changes to the market and an evaluation was made of the most important effects on ancillary services procurement. It was found that all of the nodal protocol revisions considered produced changes in terms of the procured regulation-up and regulation-down reserves. Moreover, it was found that installed power, regardless of its type (e.g. coastal wind, non-coastal wind, thermal) is positively correlated with procured reserves. An exception for this was during the time before the nodal market introduction, where coastal wind was negatively correlated with reserves procurement.

The results obtained suggest that the changes in requirements for procured reserves due to protocol revisions performed during the transition between zonal to nodal market have been more significant than the changes in requirements due to increases in installed wind power capacity for around 8,000 MW for the period within 2007 to 2013. This observation motivates the exploration of better ways to operate the grid allowing more renewable integration without significant additional cost due to its fluctuations. To illustrate this situation, let's consider Figure 15 where it is conceptually represented a change in operational conditions in the system (e.g. a new network protocol revision). By doing this change, the reserve requirements change from point 1 to point 1'. Now after an increase in installed wind power, the operational reserves requirements reductions by the operation condition improvements are offset by the additional operating reserves required due to new renewable generation. Notice that without this change the operational reserves associated to point 2 would be obtained instead of 2', which may have significant economic consequences in the operation of the power market.

FIGURE 15

Illustration of operation reserves requirements change due to operational conditions changes.



APPENDIX: Impact analysis of wind related nodal protocol revision requests on ancillary services requirements

BACKGROUND

The requirements for ancillary services in markets such as ERCOT are determined by policies that consider past data, as well as forecasts for future conditions to determine adequate quantities to be procured. This section provides an analysis of correlation and causation of ancillary services requirements and other system variables and the changes in these relationships due to changes in the underlying "protocols" of the ERCOT market. To facilitate the discussion, a list of "nodal protocol revision requests" (NPPRS) is first developed that is related to ancillary services and then reviewed. Secondly, some variables are identified that are correlated with ancillary reserves requirements. Finally, a statistical methodology is used to test whether NPRRs have changed ancillary services requirements.

IDENTIFICATION OF ANCILLARY SERVICES RELATED PROTOCOLS

This report covers a study period between 01/01/2007 to 04/13/2014 in ERCOT. During that period, several major changes to ERCOT system have occurred. After the introduction of the nodal market, which itself is the most momentous change to the market over this period, these changes have been called Nodal Protocol Revision Requests (NPRRs). Given that utility scale renewable generation is a significant source of variability and uncertainty in the system, it is expected that the protocol revisions related to this type of generation have an impact on ancillary services requirements. It is for the above reason that this report is focused on the analysis of NPRRs related with wind generation. By searching for wind related protocols, a preliminary list of protocols presented was constructed, which is presented in Table 5.[2] In this table, the protocol revisions that are not sufficiently related with ancillary services were discarded. For example NPRR389, NPRR423, and NPRR424 are related with reactive compensation and were discarded since reactive compensation is very weakly related with operating reserves provisions, which are mostly related with active power.

Amongst the remaining NPRRs that are related to wind operation and forecast, there is a group that was effective upon the Texas Nodal Market implementation. Therefore, it is not possible to temporally isolate their individual impact on ancillary services requirements, nor is it possible to isolate their impact from the impact of the change to the nodal market itself, including the change from 15 minute portfolio-based dispatch to 5 minute unit-specific dispatch. Similarly, several other groups of NPPRs were implemented during short periods of time. Based on the implementation dates of the selected protocols, the whole study period was split in five periods as presented in Table 6. This study identifies changes in AS requirements that can be associated with the groups of protocol revisions in Table 5.

2 The help of Walter Reid, Shams Siddiqi, and Dan Jones is gratefully acknowledged in providing this preliminary list.

TABLE 5

Selected ERCOT nodal protocols related with ancillary services (*): Effective upon Texas Nodal Market Implementation.

N	Name	Title	Selected	Approval date	Implementation Effective date	Description
1	NPRR045 (*)	Wind Power Forecasting	✔	10/16/2007	11/1/2007	It clarifies the production of ERCOT wind forecasts with a 80% of probability of confidence.
2	NPRR050 (*)	Clarifications for HSL Values for WGRs and WGR Values to be Used in the RUC Capacity Short Calculation	✔	07/17/2007	08/01/2007	It corrects an inconsistency in the protocols and clarify the values for wind generation resources to be used in the reliability unit commitment.
3	NPRR159 (*)	Resource Category Startup Offer Generic Cap for Wind Resources	✘	01/20/2009	02/01/2009	It stablishes that the O&M cost for wind is zero.
4	NPRR177 (*)	Synchronization of Nodal Protocols with PRR808, Clean-up and Alignment of RECs Trading Program Language with PUCT Rules	✘	08/18/2009	09/01/2009	It has to be with renewable energy credits under the ERCOT nodal market operation.
5	NPRR210 (*)	Wind Forecasting Change to P50, Synchronization with PRR841	✔	06/15/2010	07/01/2007	IT changes the wind forecasting methodology to use 50% of probability of exceedance instead of 80% for Reliability Unit Commitment considerations.
6	NPRR214 (*)	Wind-powered Generation Resource (WGR) High Sustained Limit (HSL) Update Process	✔	05/18/2010	01/01/2010	It clarifies the timing for providing the maximum sustained production limit by wind generation resources.
7	NPRR239 (*)	Ramp Rate Limitation of 10% per minute of On-Line Installed Capability for Wind-powered Generation Resources	✔	07/20/2010	08/01/2010	It limits the unit ramp rate of wind generation resources to 10% of their nameplate rating.
8	NPRR258 (*)	Synchronization with PRR824 and PRR833 and Additional Clarifications	✔	11/16/2010	12/01/2010	It aligns nodal protocols with primary frequency requirements for wind generation resources.
9	NPRR270 (*)	Defining the Variable Used in the Wind Generation Formula	✘	11/16/2010	12/01/2010	It is related with consideration of wind generation at distributed level for transmission and distribution service providers.
10	NPRR281 (*)	Replace 7-Day Forecast Requirement for QSEs Representing WGRs	✔	11/16/2010	12/01/2010	It eliminates the requirement that qualified scheduling entities must provide a 7 day forecast. It is considered that it produces unreliable results.
11	NPRR285 (*)	Generation Resource Base Point Deviation Charge Corrections	✔	11/16/2010	12/01/2010	It provides a clear curtailment signal for intermittent renewable resources.
12	NPRR352	Real-Time HSL Telemetry for WGRs	✔	05/17/2011	6/1/2011	It is related with improvements in the prediction of the maximum sustained energy production capability of a wind generator after curtailment.

13	NPRR361	Real-Time Wind Power Production Data Transparency	✔	8/16/2011	9/1/2011	It requires the submitting of 5 min resolution wind data for real time purposes.
14	NPRR389	Modification of Voltage Support Requirements to Address Existing Non-Exempt WGRs	✘	10/18/2011	11/1/2011	It clarifies the reactive power capability for wind power generation resources.
15	NPRR423	Add Voltage Support Requirement for IRRs and Allow SCADA Control of Static VAr Devices if Approved by ERCOT	✘	2/21/2012	3/1/2012	It clarifies voltage and reactive requirements for intermittent renewable resources.
16	NPRR424	Reactive Capability Testing Requirements for IRRs	✘	4/17/2012	5/1/2012	It defines the reactive testing requirement for intermittent renewable resources.
17	NPRR425	Creation of a WGR Group for GREDP and Base Point Deviation Evaluation and Mixing Turbine Types Within a WGR (formerly "Creation of a WGR Group for GREDP and Base Point Deviation Evaluation")	✘	11/13/2012	12/1/2012	It proposes the aggregation of wind farms in groups for dispatch purposes, to avoid control limitations.
18	NPRR437	Allow Aggregation of Multiple Generators Into A Single Resource For Market and Engineering Modeling	✘	02/21/2012	03/01/2012	It allows the aggregation of similar qualified non-wind powered generators for market and engineering modeling purposes.
19	NPRR460	WGR Ramp Rate Limitation	✔	11/13/2012	12/1/2012	It increases the wind powered generation resource ramp rate limitation from 10% per minute of nameplate rating to five minute average of 20% per minute of nameplate rating with no individual minute exceeding 25%.
20	NPRR531	Clarification of IRR Forecasting Process Posting Requirement	✘	7/16/2013	8/1/2013	It clarifies that ERCOT has to publish their procedures for forecasting, in special for intermittent renewable resources.
21	NPRR577	As-Built Clarification for Portion of WGR Group GREDP Evaluation	✘	2/11/2014	3/1/2014	It is a clarification of NPRR425.
22	NPRR611	Modifications to CDR Wind Capacity Value	✘	10/14/2014	11/01/2014	It proposes modifications to the Capacity, Demand, and Reserves methodology for calculating capacity value of wind during peak load periods.
23	NPRR678	Posting of Wind Peak Average Capacity Percentage Data	✘	04/14/2015	05/01/2015	It is about the requirement of information to calculate wind peak average capacity percentages in ERCOT webpage.

CORRELATION ANALYSIS OF STUDY PERIODS

For each time period defined in Table 6, a regression analysis was performed to obtain a regression model for the required ancillary services reserves. In this report, only regressions for regulation-up and regulation-down were performed since preliminary investigation of the other AS suggests that they will not be affected by the NPRRs. The outcome variables are the ones presented in Table 7. The data used for regression were the hourly procured regulation-up and regulation-down in ERCOT.

The proposed regressors are the ones presented in Table 8, and their data is presented in Figures Figure 16 - Figure 21. The idea behind this selection is to represent the factors that will likely affect the procured quantities of regulation reserves, which depend on the uncertainty in generation and demand.

TABLE 6

Study periods for NPRRs.

Study period	Description	Start	End	Duration [days]
1	Pre-Nodal market	1/1/2007	12/01/2010	1430
2	NPRR045, NPRR050, NPRR210, NPRR214, NPRR239, NPRR258, and other zonal to nodal market changes	12/01/2010	06/01/2011	182
3	NPRR352	06/01/2011	09/01/2011	92
4	NPRR361	09/01/2011	12/01/2012	457
5	NPRR460	12/01/2012	04/13/2014	498

TABLE 7

Variables to be regressed.

Symbol	Description
	Expected value for regulation-up reserve in the study period at time.
	Expected value for regulation-down reserve in the study period at time.

TABLE 8

Regressors selected for ancillary services correlation analysis.

Symbol	Description	Units	Source
	ERCOT non-coastal wind generation accumulated installed power at time.	MW	[22]
	ERCOT coastal wind generation accumulated installed power at time.	MW	
	ERCOT thermal generation accumulated installed power at time at time.	MW	
	Daily average total load in ERCOT at time.	MW	[23]
	Daily total minimum load in ERCOT at time.	MW	
	Daily total maximum load in ERCOT at time.	MW	

FIGURE 16

ERCOT non-coastal wind generation accumulated installed power.

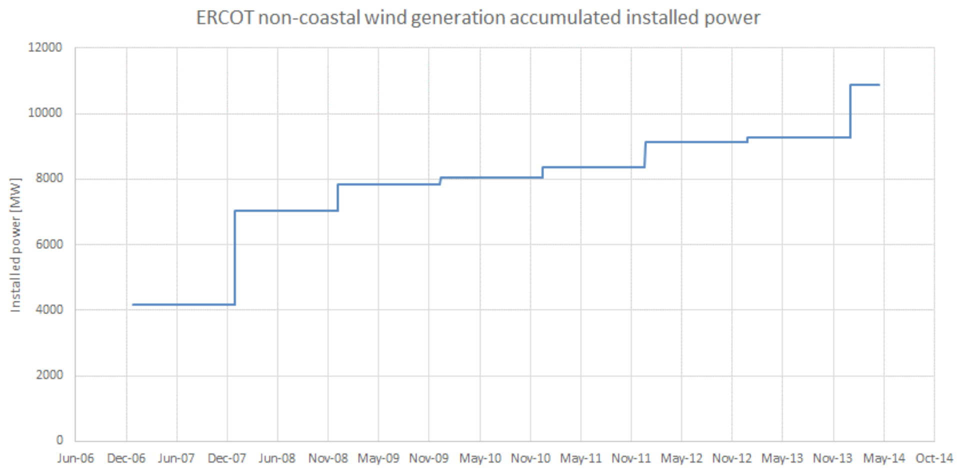


FIGURE 17

ERCOT coastal wind generation accumulated installed power.

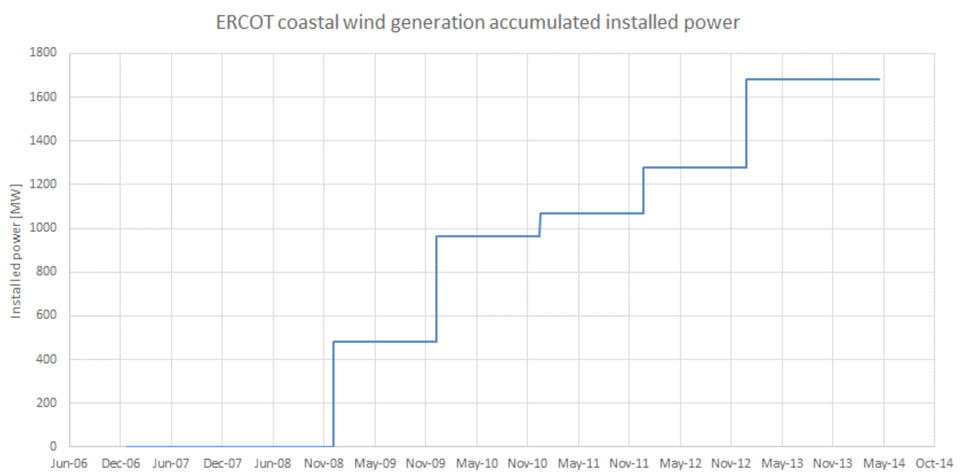


FIGURE 18

ERCOT thermal generation accumulated installed power.

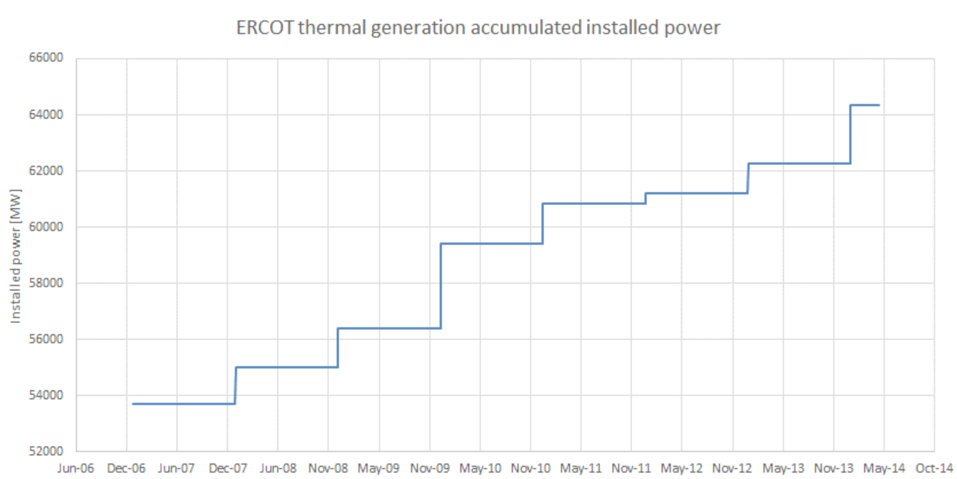


FIGURE 19

Daily average total load in ERCOT.

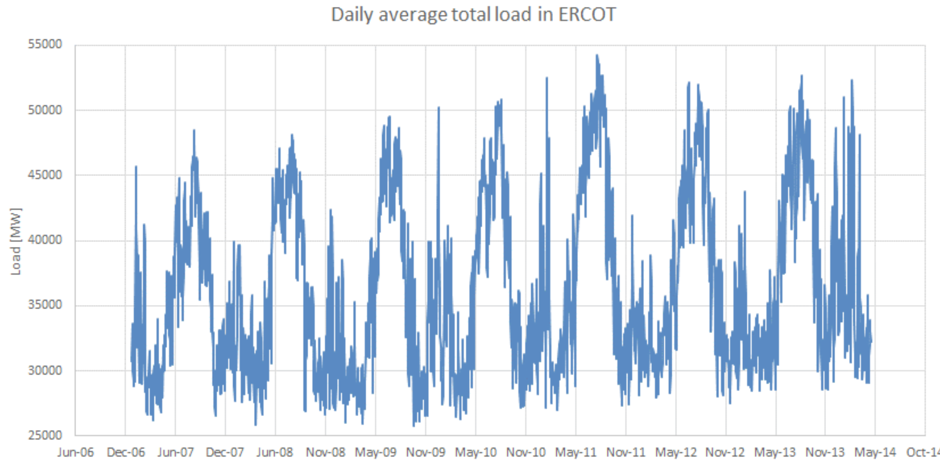


FIGURE 20

Daily total minimum load in ERCOT.

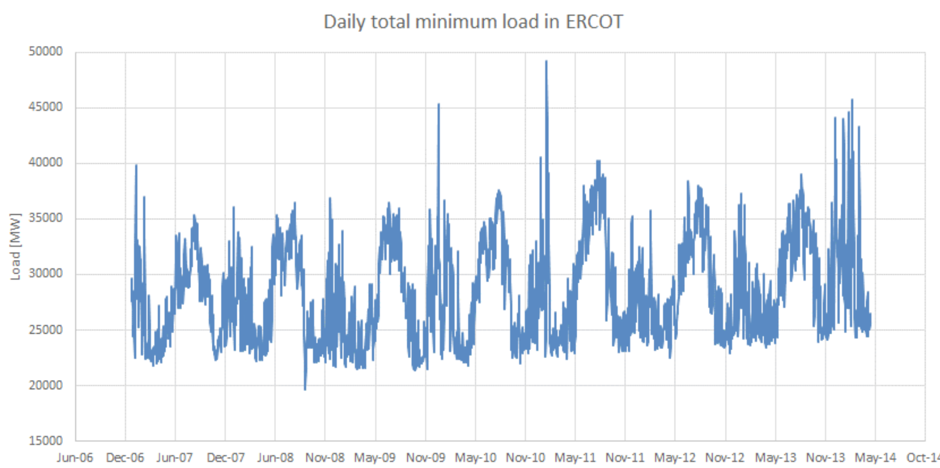
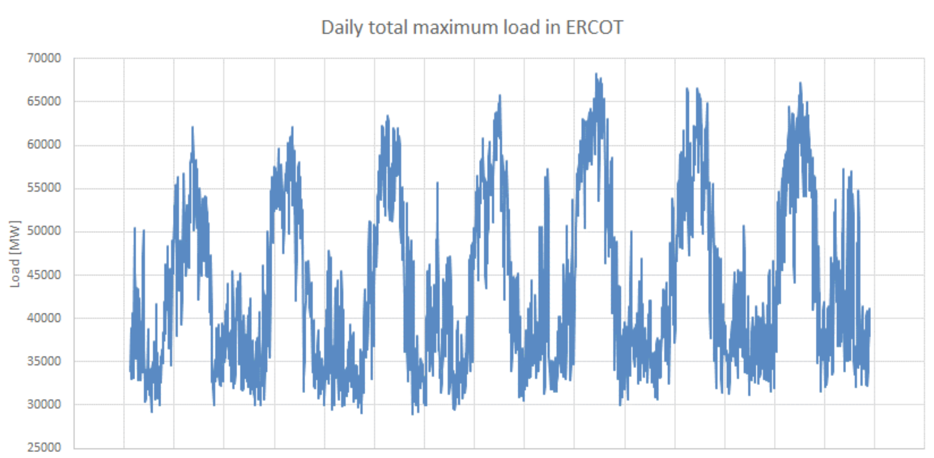


FIGURE 21

Daily total maximum load in ERCOT.



The regression model evaluated for each study period has the following functional form:

(7)

$$\widehat{U_{p,t}} = A_{p,0} + \sum_{j=1}^{6} V_{j,t} A_{p,j},$$

(8)

$$\widehat{D_{p,t}} = B_{p,0} + \sum_{j=1}^{6} V_{j,t} B_{p,j},$$

where $A_{p,j}$ and $B_{p,j}$ are coefficients associated with the model. After performing regressions for regulation-up and regulation-down for each study period independently, the information about the residuals is the one presented in figures Figure 22 to Figure 41. It can be appreciated that although there is a correlation between the regressors and outcomes, the residuals obtained are far from white noise. In particular, in the autocorrelation plots of the residuals, it can be appreciated that regression residuals are correlated with the ones of the previous 30 days. This observation suggests the necessity of including lags in the regression to cope with autocorrelation. This consideration has a physical meaning. First, the operational reserves requirement from one month to the next tend to be similar. Moreover, system operators tend to adjust reserve requirements compared to the most recently procured reserves, which are correlated with the programmed reserves. Thus, it is considered to include 30 day lags in the regression models by modifying equations (7) and (8) in the following way:

(9)

$$\widehat{U_{p,t}} = A_{p,0} + \sum_{j=1}^{6} V_{j,t} A_{p,j} + \sum_{j=1}^{30} F_{p,j} U_{p,t-j},$$

(10)

$$\widehat{D_{p,t}} = B_{p,0} + \sum_{j=1}^{6} V_{j,t} B_{p,j} + \sum_{j=1}^{30} G_{p,j} D_{p,t-j},$$

where $F_{p,j}$ and $G_{p,j}$ are coefficients associated with lag variables. Tables Table 9 - Table 18 present the regression coefficients for the significant regressors. The impact of including lags in the regression can be appreciated in the autocorrelations of the residuals, which are much smaller. Notice that in most of the cases, in comparison with the case without lags, the residuals autocorrelations were decreased. However, in some cases such as the one for regulation-Up for study period 2, the autocorrelations are still significant, which indicates that the regression models are not complete yet. This issue will be addressed in a future report.

TABLE 9

Significant regression coeffients for Regulation-Up in study period 1 (with 5% of significance).

Parameter	Coefficient	p-value
$A_{1,2}$	-0.002280	0.009
$A_{1,3}$	0.000717	0.000
$A_{1,5}$	-0.000201	0.007
$F_{1,1}$	0.8883	0.000
$F_{1,2}$	0.0713	0.008

TABLE 10

Significant regression coefficients for Regulation-Down in study period 1 (with 5% of significance).

Parameter	Coefficient	p-value
$B_{1,1}$	0.001942	0.002
$B_{1,3}$	0.001199	0.000
$B_{1,4}$	0.000335	0.007
$G_{1,1}$	0.2905	0.000
$G_{1,2}$	0.2132	0.000
$G_{1,3}$	0.1565	0.000
$G_{1,4}$	0.1227	0.000
$G_{1,5}$	0.1059	0.000

TABLE 11

Significant regression coeffients for Regulation-Up in study period 2 (with 5% of significance).

Parameter	Coefficient	p-value
$A_{2,0}$	-2691	0.000
$A_{2,1}$	0.3483	0.000
$A_{2,4}$	0.002031	0.009
$A_{2,5}$	-0.003305	0.000
$F_{2,1}$	0.4511	0.000
$F_{2,30}$	0.1791	0.000

TABLE 12

Significant regression coefficients for Regulation-Down in study period 2 (with 5% of significance).

Parameter	Coefficient	p-value
$B_{2,0}$	-3129	0.000
$B_{2,3}$	0.05739	0.000
$B_{2,4}$	0.00472	0.000
$B_{2,5}$	-0.004022	0.000
$B_{2,6}$	-0.001094	0.047
$G_{2,1}$	0.1236	0.000
$G_{2,30}$	0.1151	0.000

TABLE 13

Significant regression coeffients for Regulation-Up in study period 3 (with 5% of significance).

Parameter	Coefficient	p-value
$A_{3,6}$	0.000222	0.034
$F_{3,1}$	0.9774	0.000

TABLE 14

Significant regression coefficients for Regulation-Down in study period 3 (with 5% of significance).

Parameter	Coefficient	p-value
	131.5	0.003
	0.9117	0.000
	-0.1672	0.004

TABLE 15

Significant regression coeffients for Regulation-Up in study period 4 (with 5.3% of significance).

Parameter	Coefficient	p-value
	0.002209	0.000
	-0.000193	0.053
	0.000117	0.010
	0.96276	0.000

TABLE 16

Significant regression coefficients for Regulation-Down in study period 4 (with 5% of significance).

Parameter	Coefficient	p-value
	0.999663	0.000

TABLE 17

Significant regression coeffients for Regulation-Up in study period 5 (with 5.1% of significance).

Parameter	Coefficient	p-value
	0.000207	0.002
	0.000198	0.032
	-0.000238	0.051
	0.97127	0.000

TABLE 18

Significant regression coefficients for Regulation-Down in study period 5 (with 5.4% of significance).

Parameter	Coefficient	p-value
	8.75	0.014
	0.000173	0.037
	-0.000207	0.054
	0.97788	0.000

FIGURE 22

Residual Plots for Regulation-Up in study period 1(without lags).

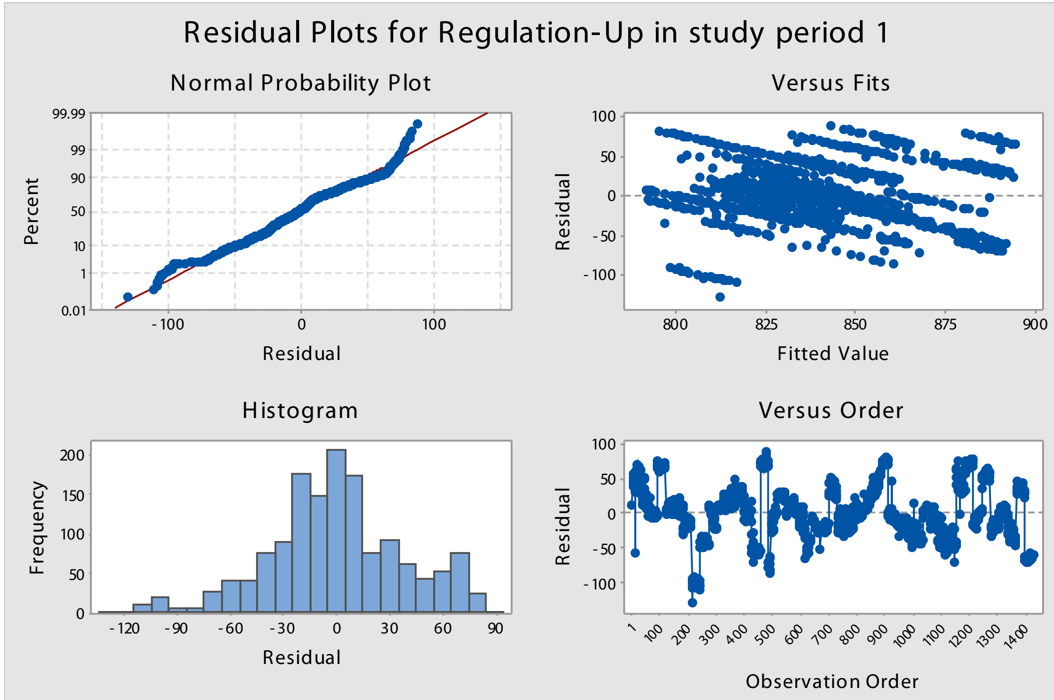


FIGURE 23

Autocorrelation Function for Regulation-Up in study period 1 residuals (without lags).

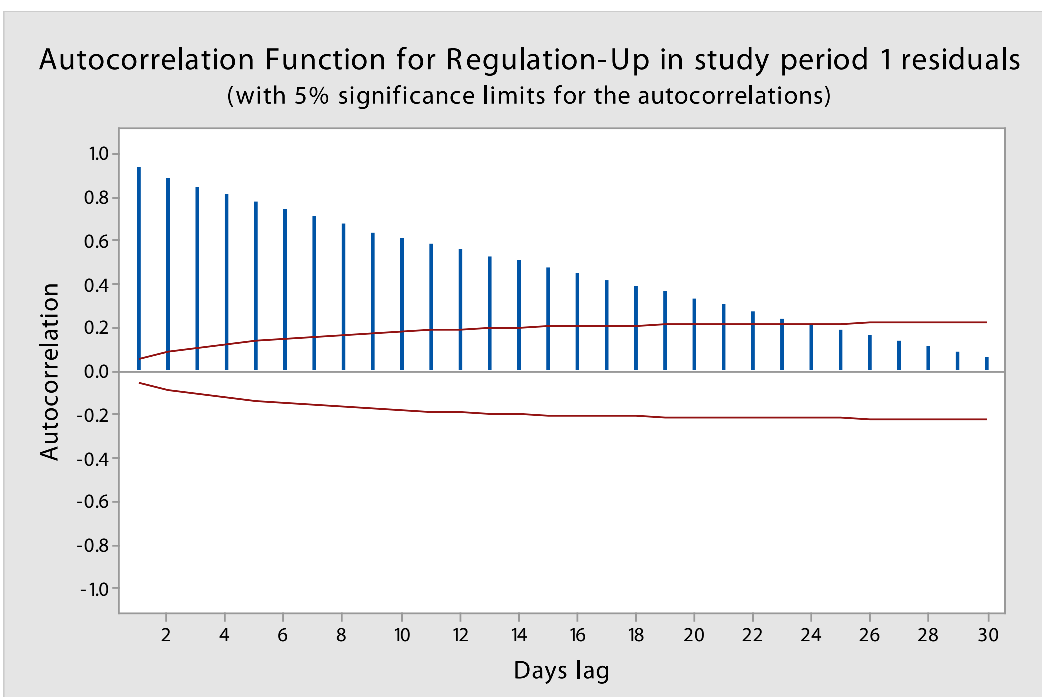


FIGURE 24

Residual Plots for Regulation-Down in study period 1 (without lags).

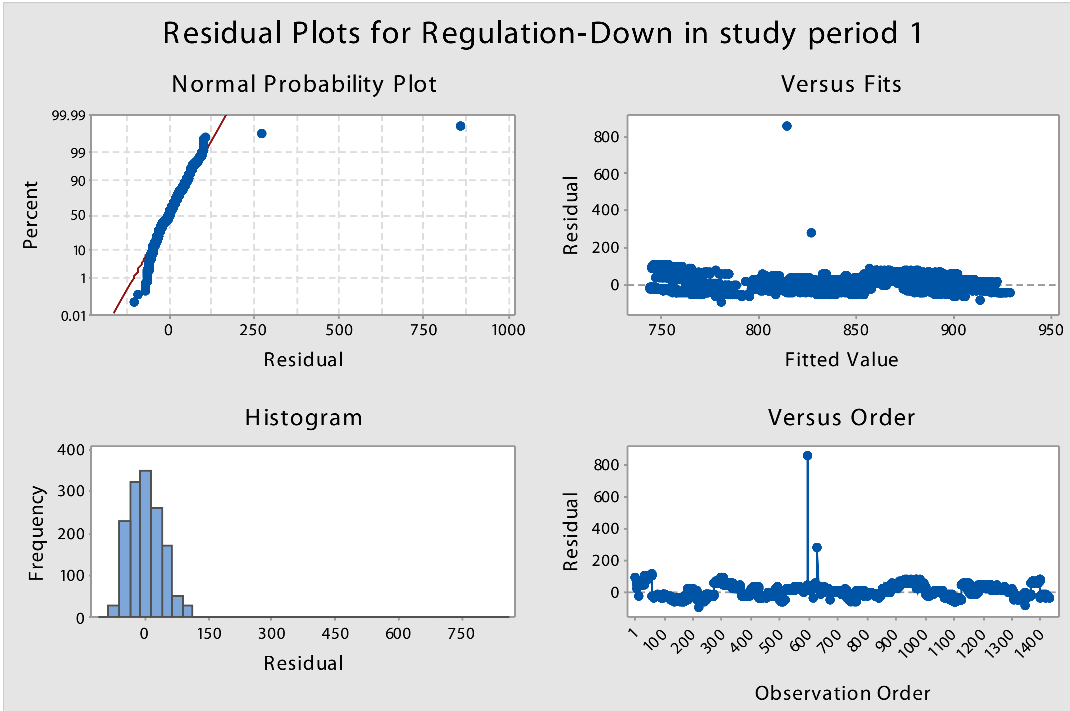


FIGURE 25

Autocorrelation Function for Regulation-Down in study period 1 residuals (without lags).

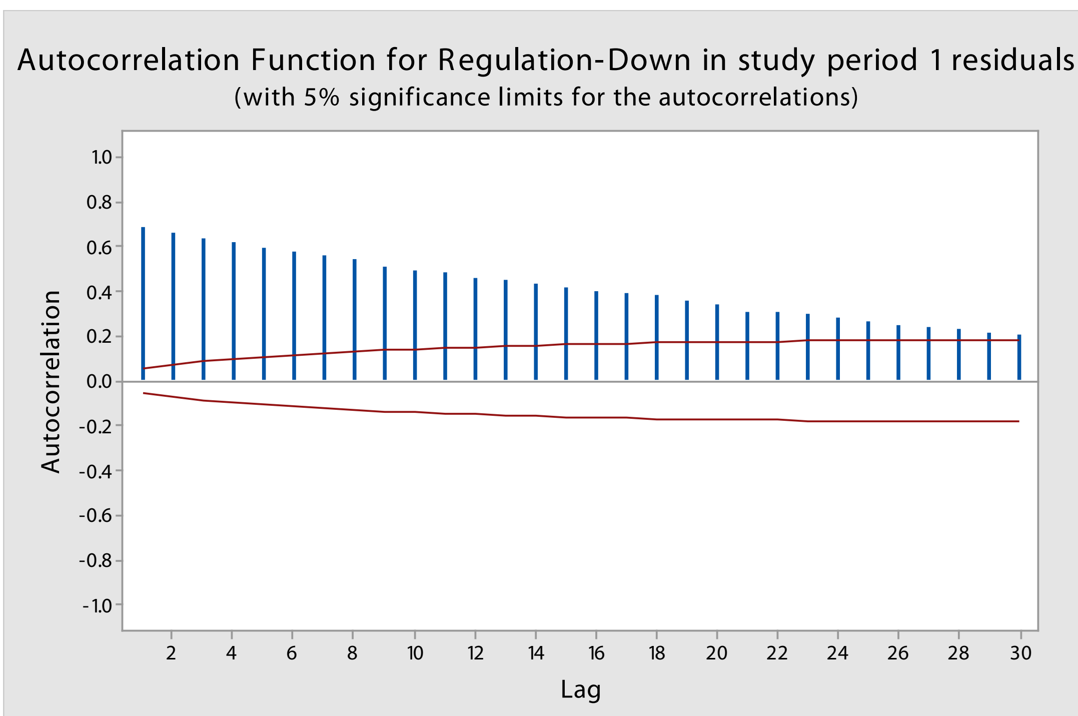


FIGURE 26

Residual Plots for Regulation-Up in study period 2 (without lags).

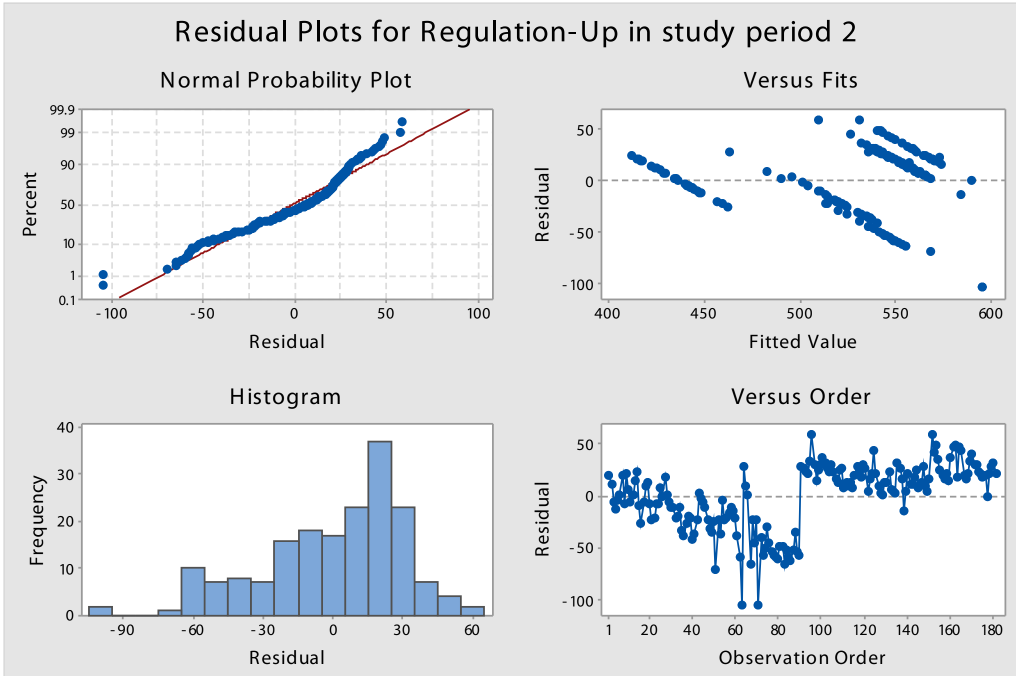


FIGURE 27

Autocorrelation Function for Regulation-Up in study period 2 residuals (without lags).

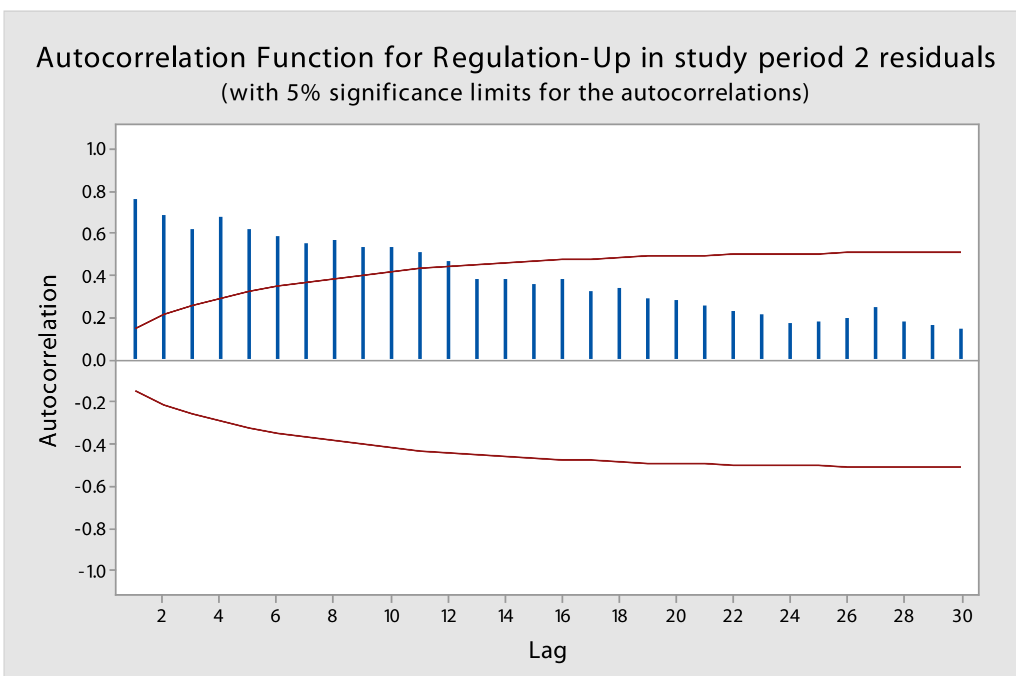


FIGURE 28

Residual Plots for Regulation-Down in study period 2 (without lags).

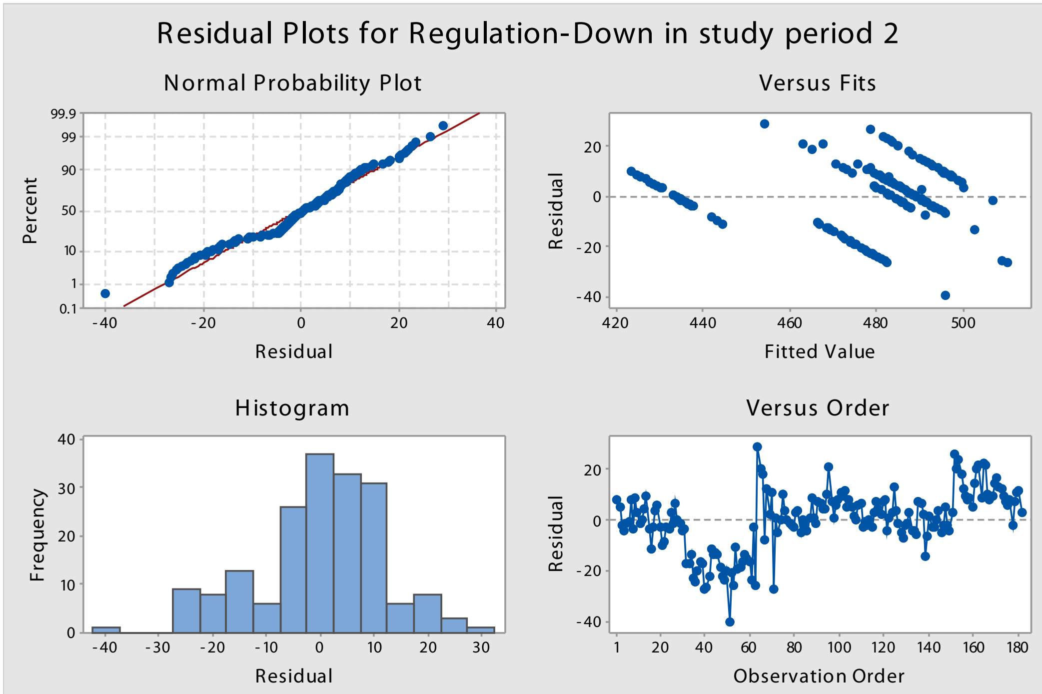


FIGURE 29

Autocorrelation Function for Regulation-Down in study period 2 residuals (without lags).

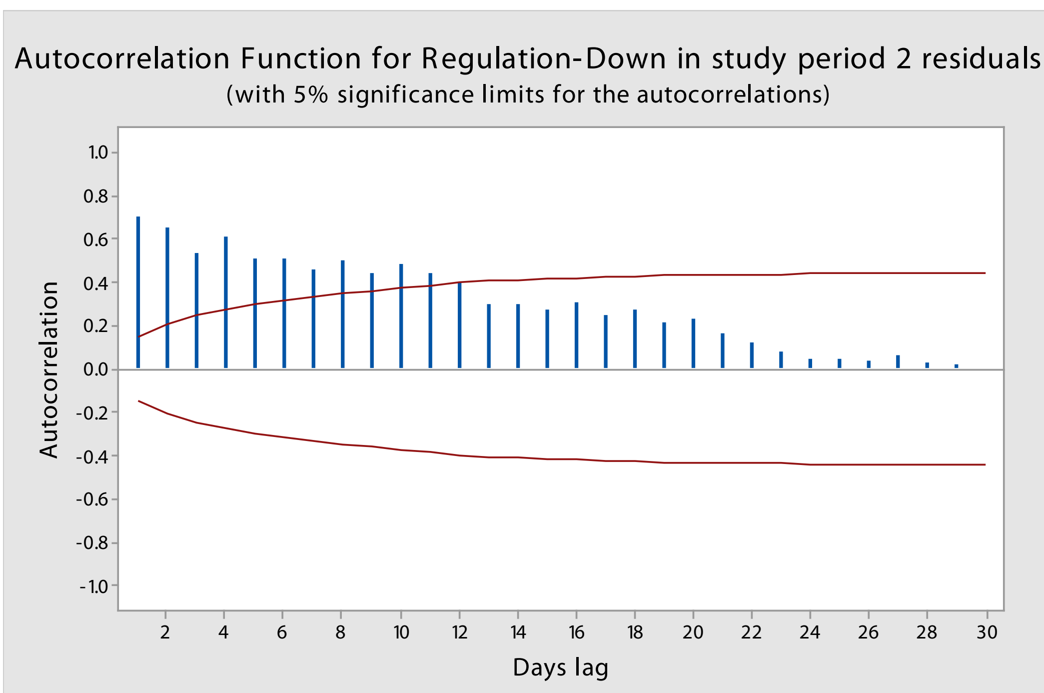


FIGURE 30

Residual Plots for Regulation-Up in study period 3 (without lags).

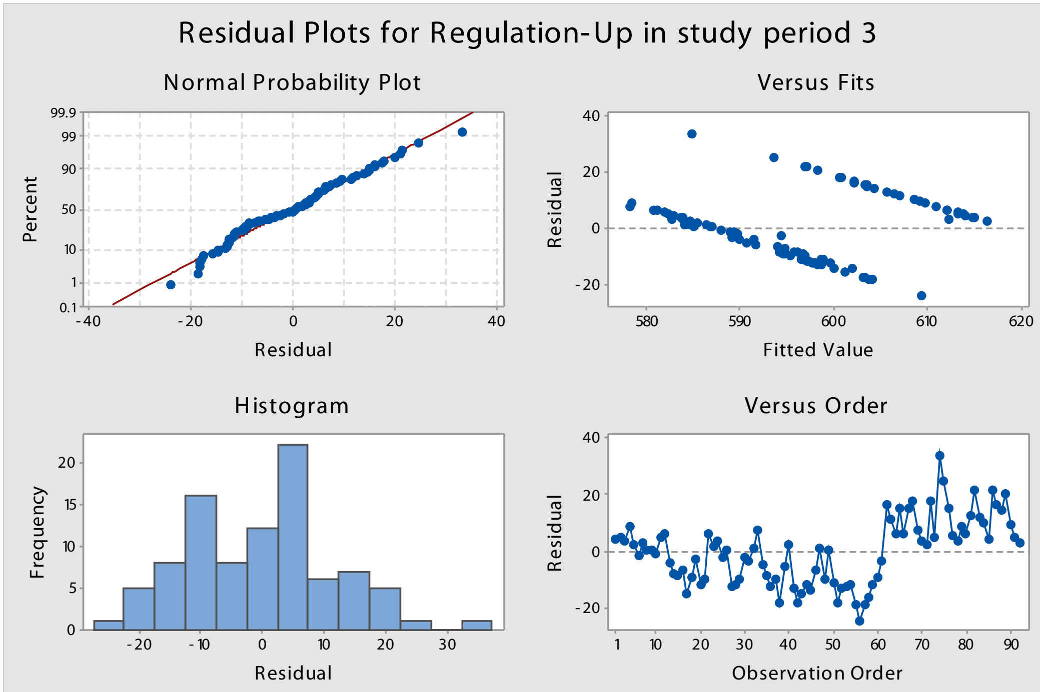


FIGURE 31

Autocorrelation Function for Regulation-Up in study period 3 residuals (without lags).

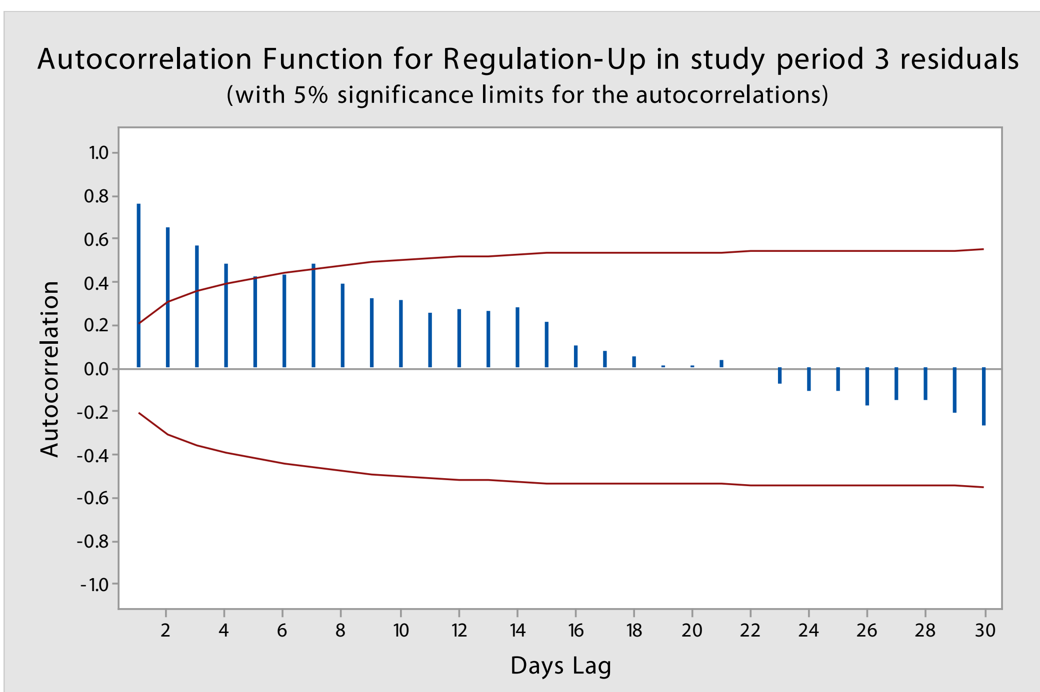


FIGURE 32

Residual Plots for Regulation-Down in study period 3 (without lags).

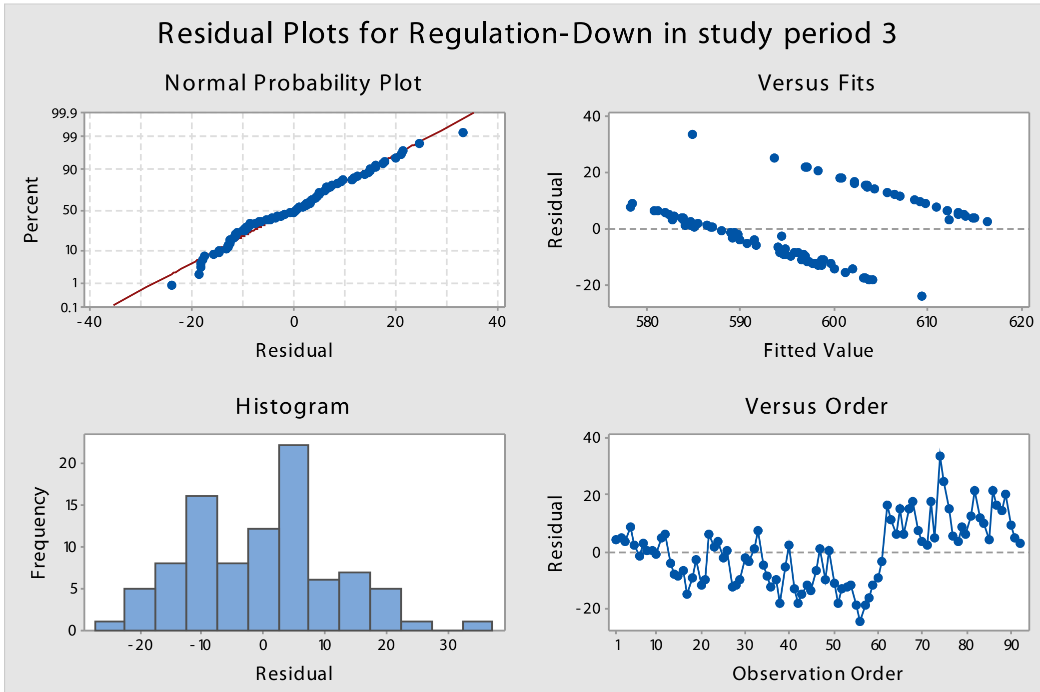


FIGURE 33

Autocorrelation Function for Regulation-Down in study period 3 residuals (without lags).

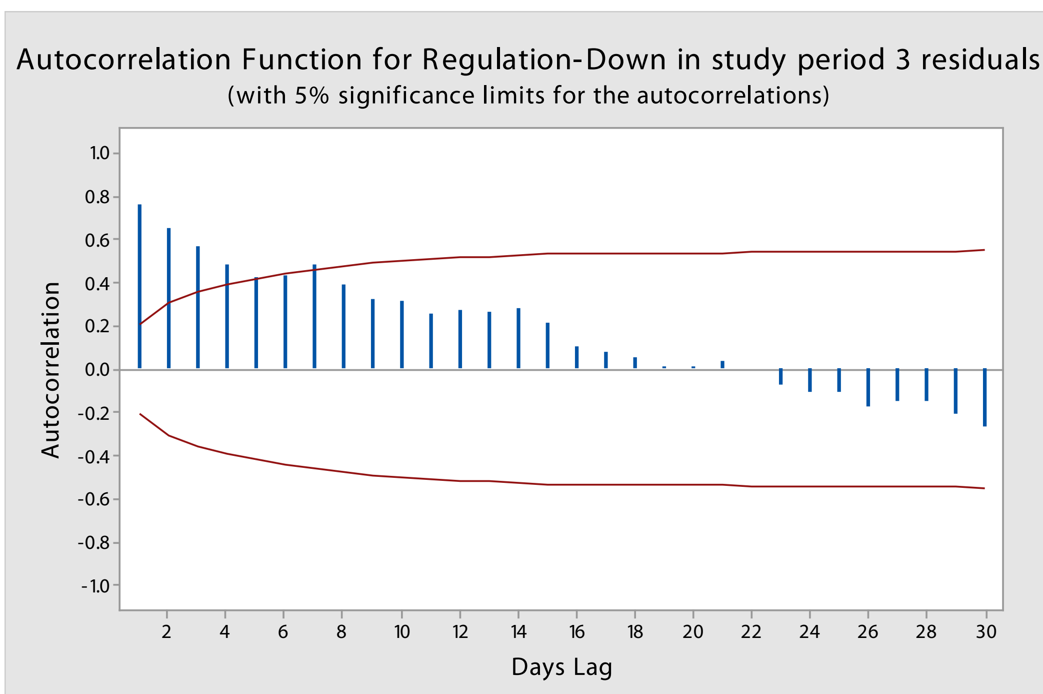


FIGURE 34

Residual Plots for Regulation-Up in study period 4 (without lags).

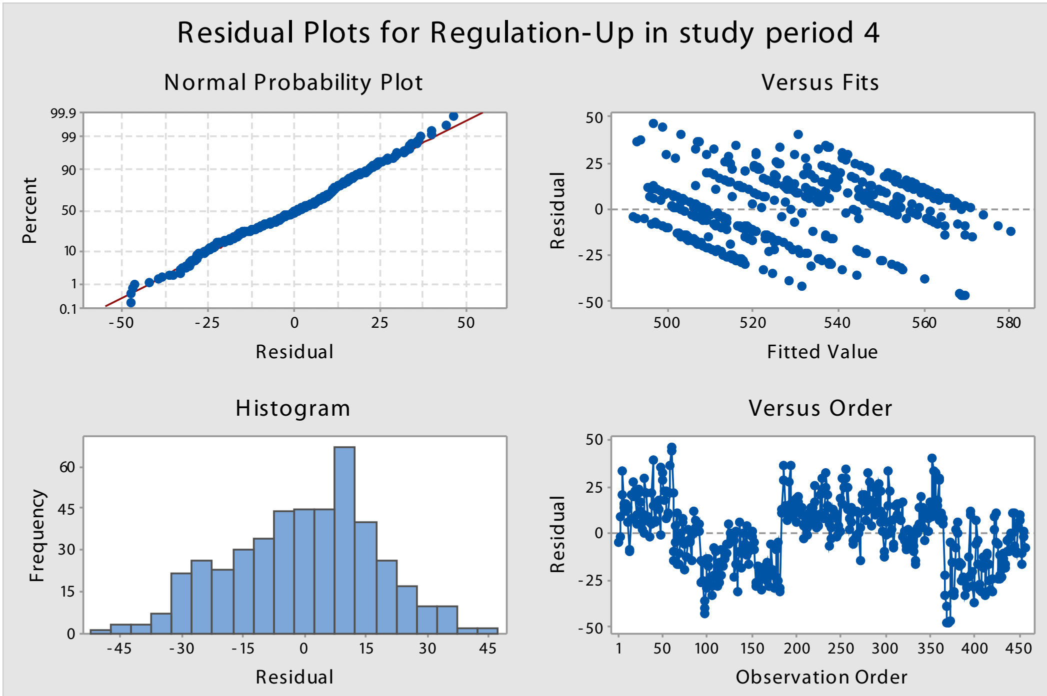


FIGURE 35

Autocorrelation Function for Regulation-Up in study period 4 residuals (without lags).

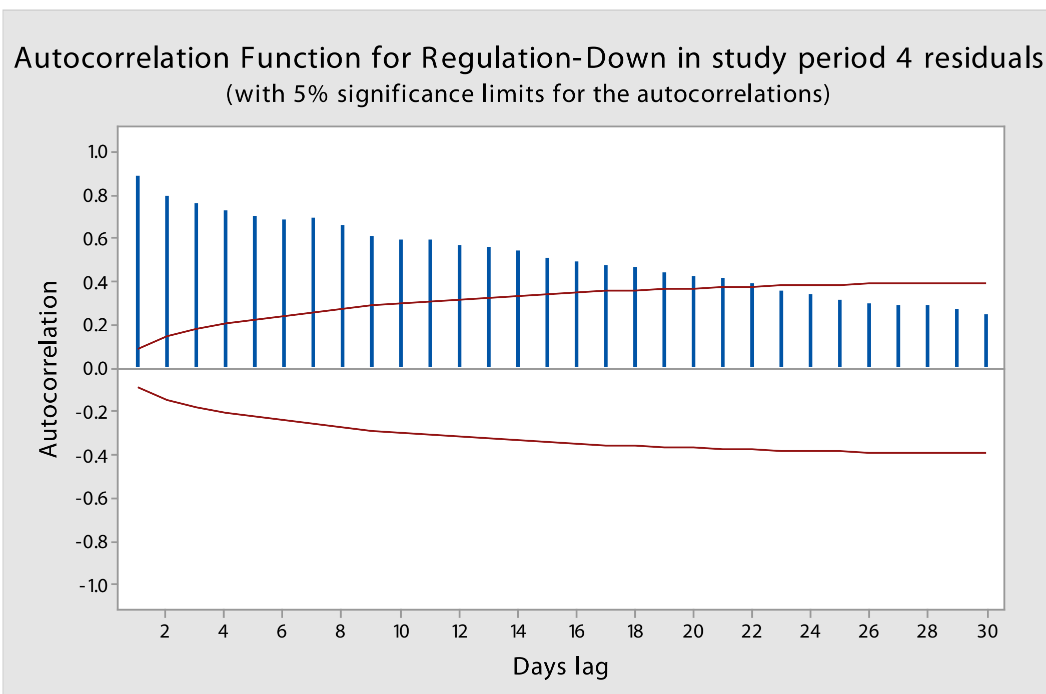


FIGURE 36

Residual Plots for Regulation-Down in study period 4 (without lags).

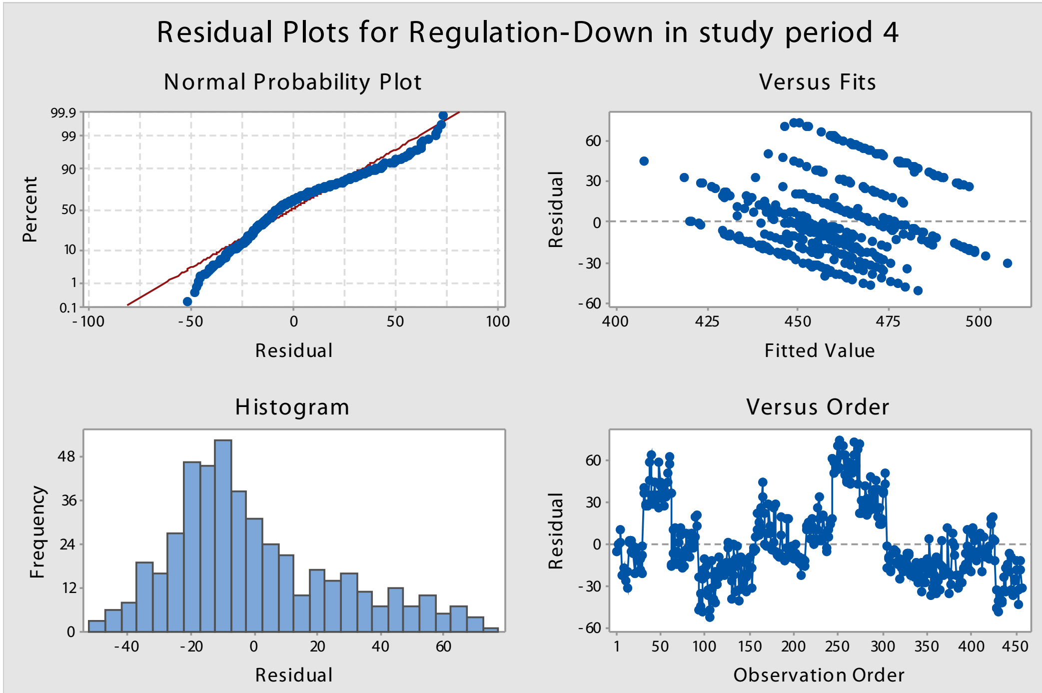


FIGURE 37

Autocorrelation Function for Regulation-Down in study period 4 residuals (without lags).

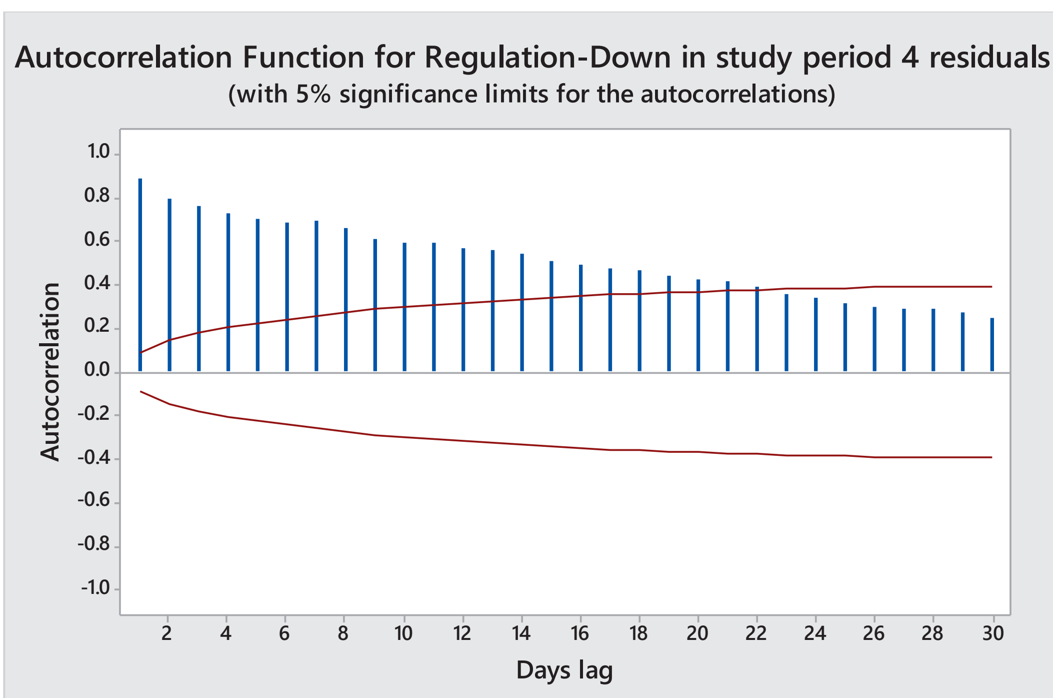


FIGURE 38

Residual Plots for Regulation-Up in study period 5 (without lags).

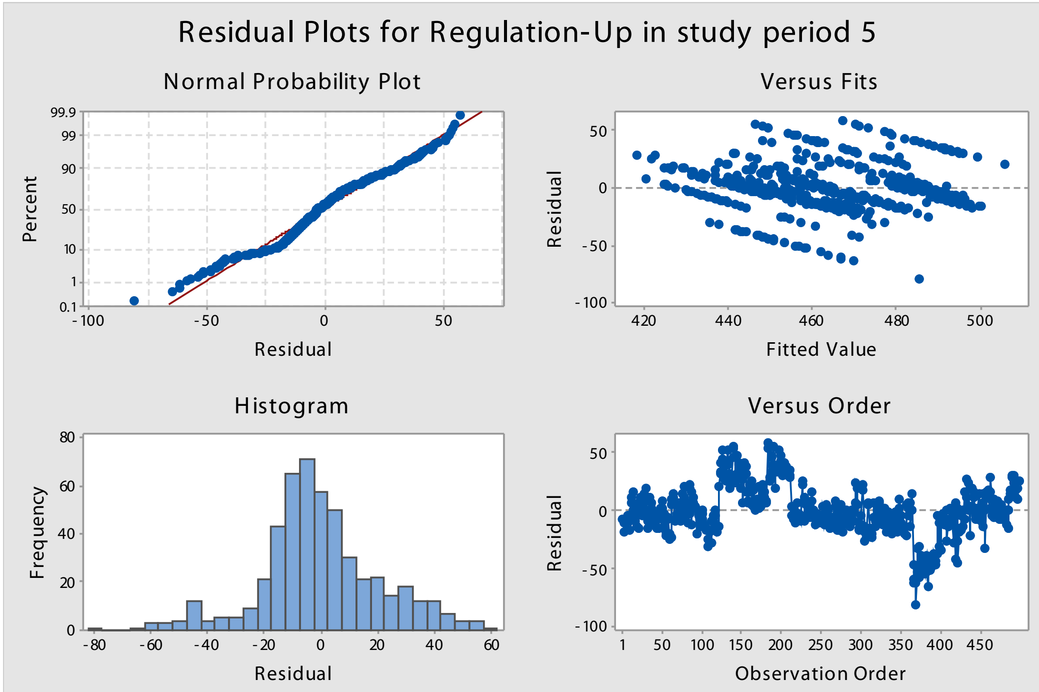


FIGURE 39

Autocorrelation Function for Regulation-Up in study period 5 residuals (without lags).

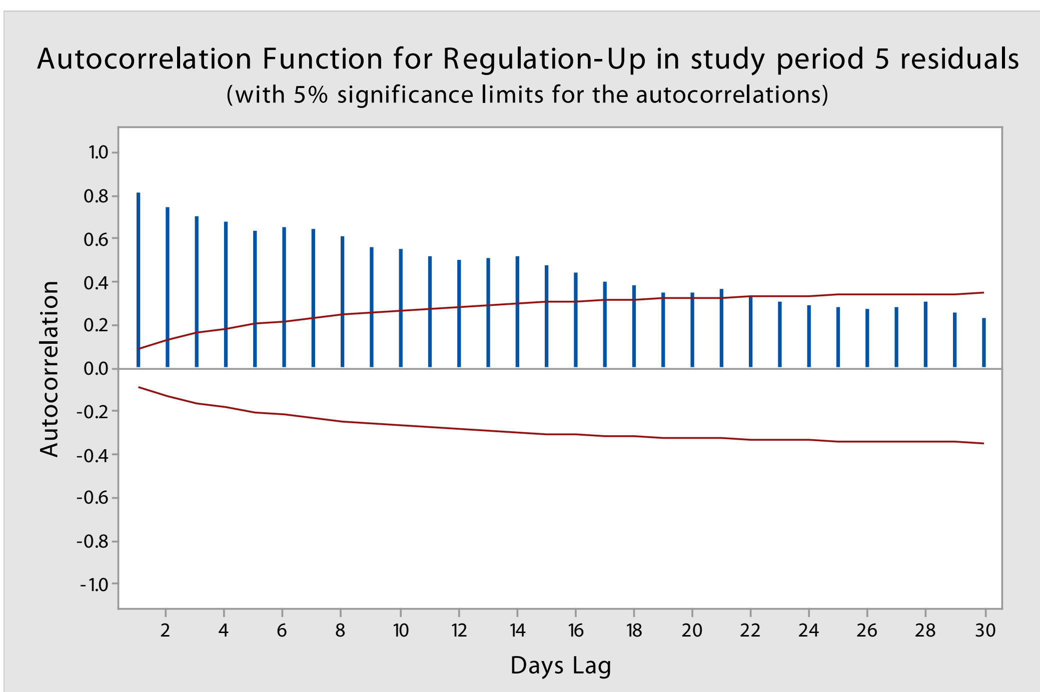


FIGURE 40

Residual Plots for Regulation-Down in study period 5 (without lags).

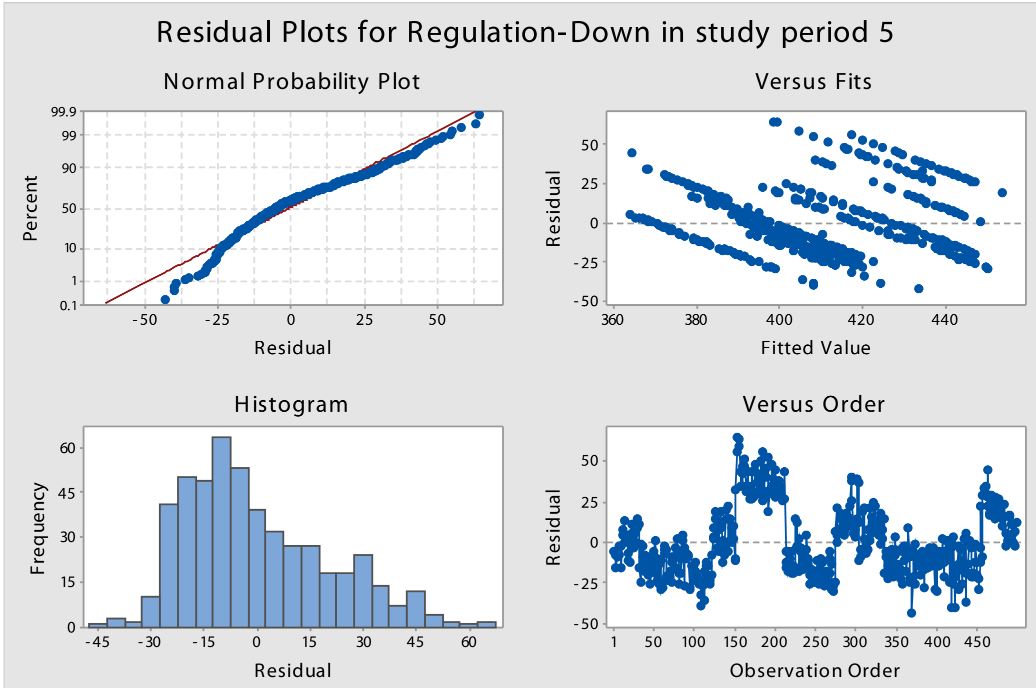


FIGURE 41

Autocorrelation Function for Regulation-Down in study period 5 residuals (without lags).

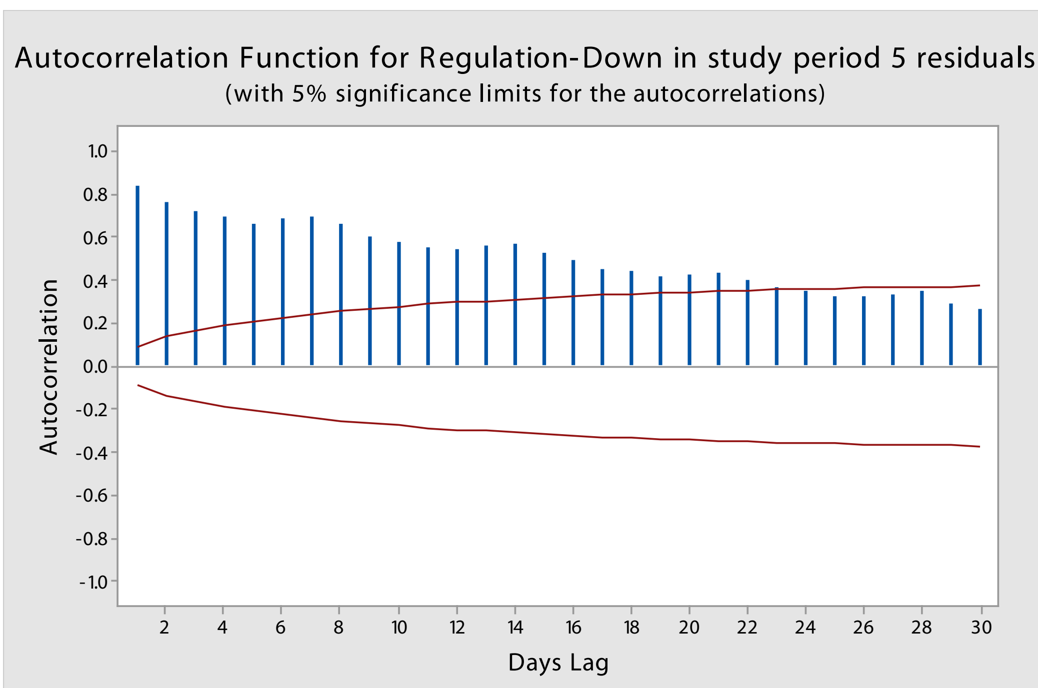


FIGURE 42

Residual Plotts for Regulation-Up in study period 1 (with lags).

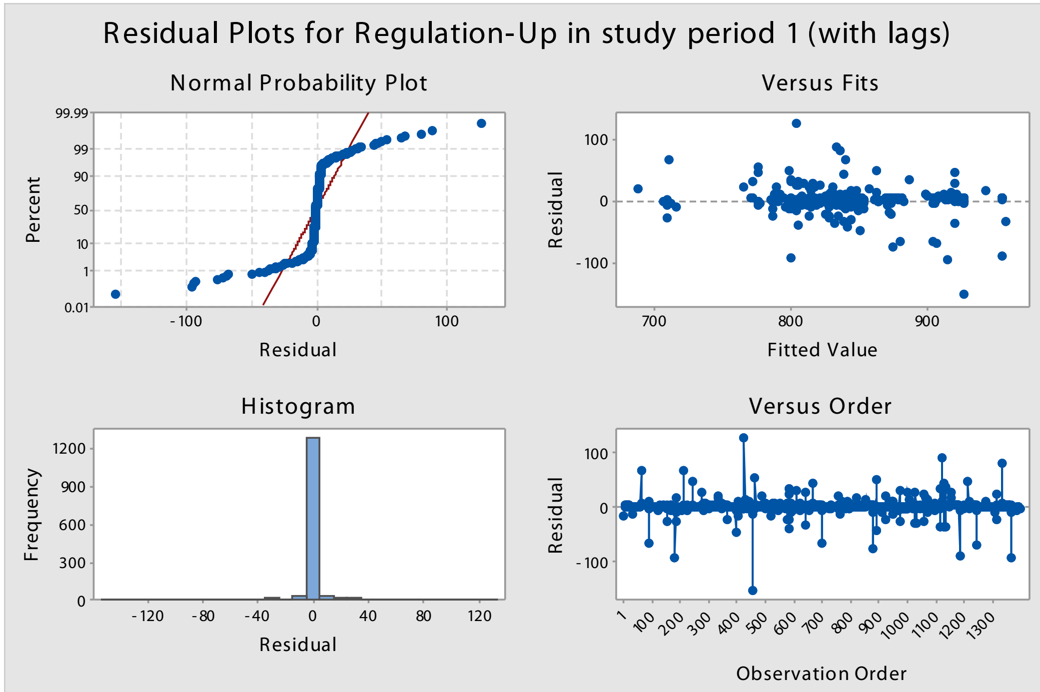


FIGURE 43

Autocorrelation Function for Regulation-Up in study period 1 residuals.

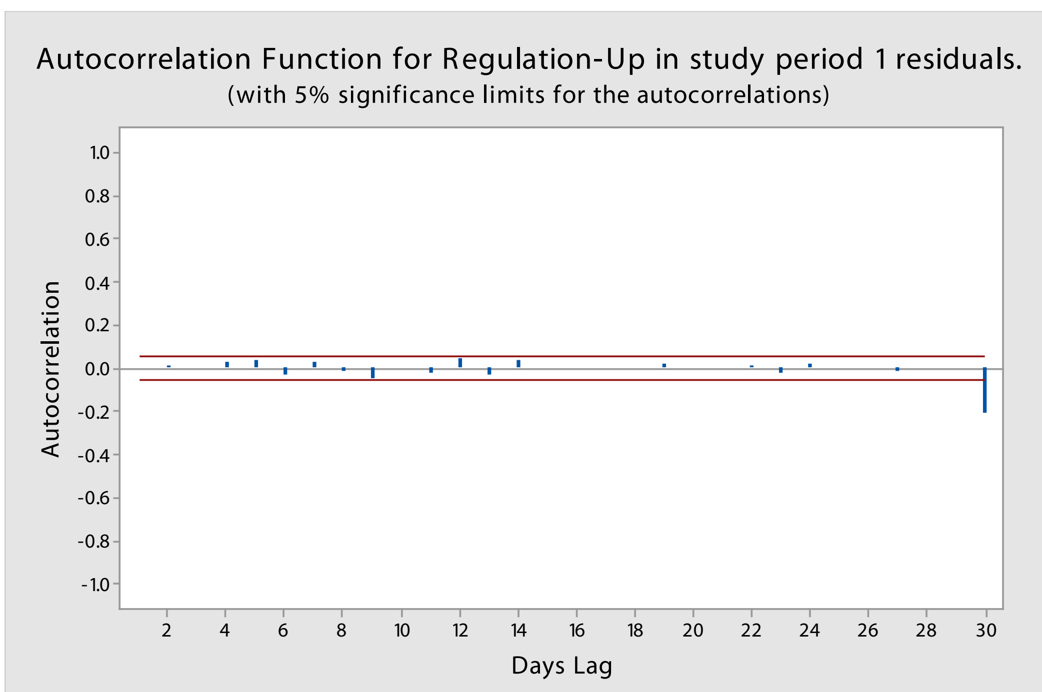


FIGURE 44

Residual Plots for Regulation-Down in study period 1 (with lags).

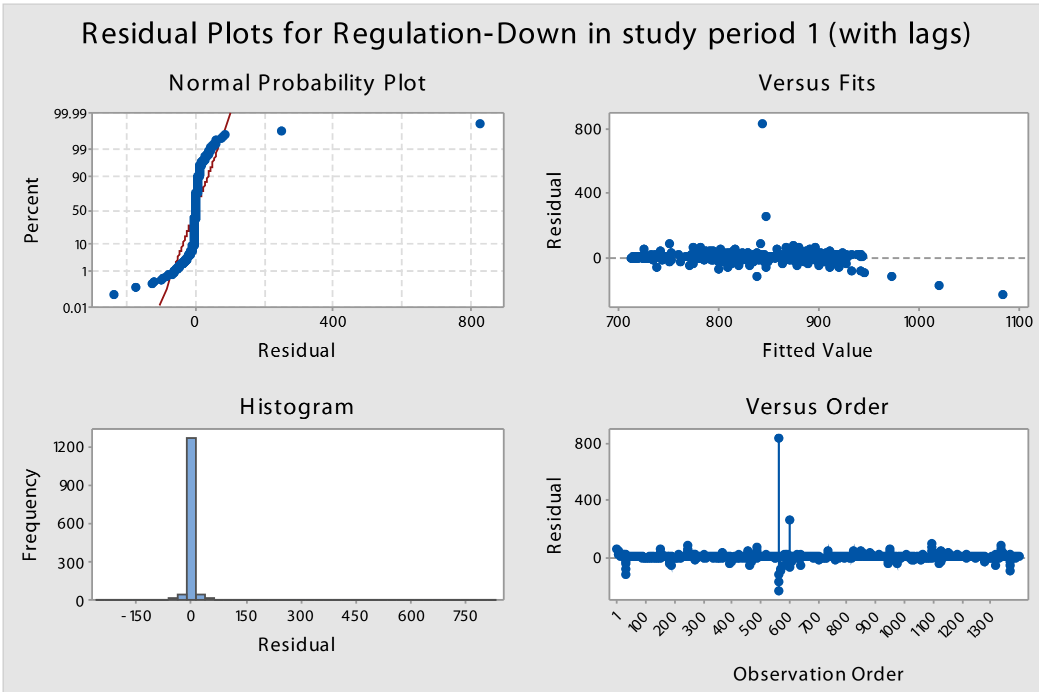


FIGURE 45

Autocorrelation Function for Regulation-Down in study period 1 residuals.

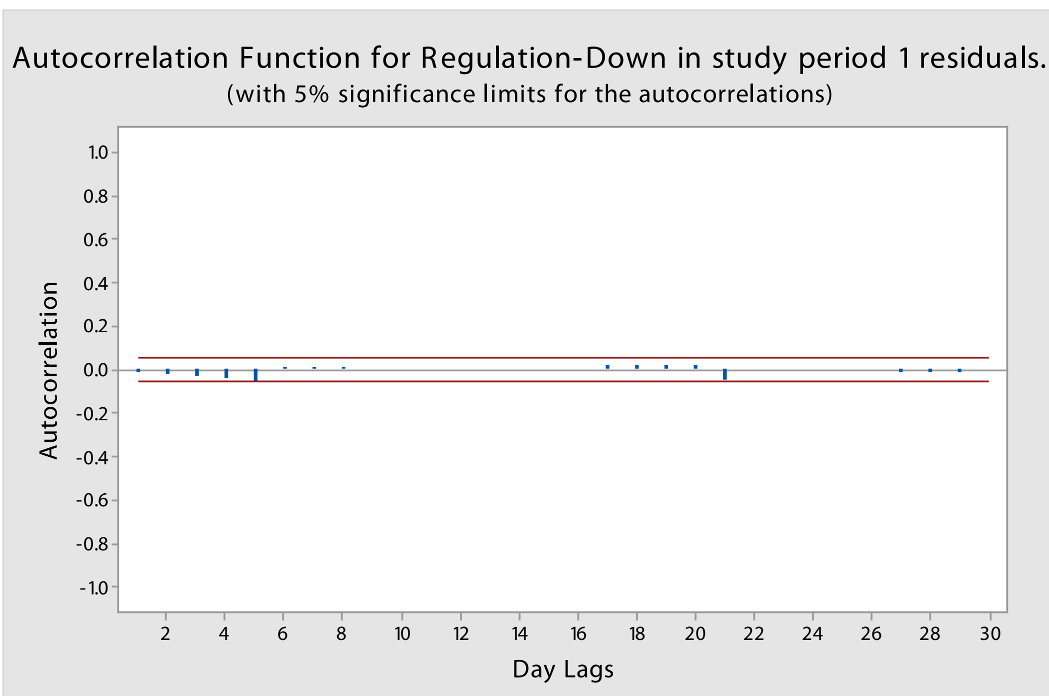


FIGURE 46

Residual Plots for Regulation-Up in study period 2 (with lags).

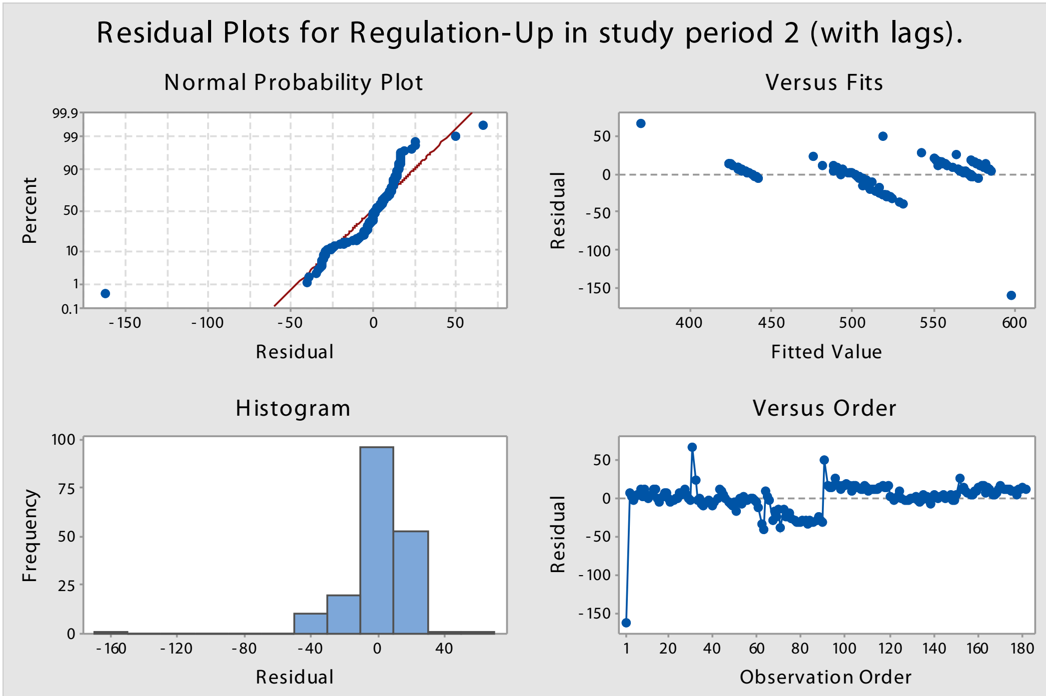


FIGURE 47

Autocorrelation Function for Regulation-Up in study period 2 residuals.

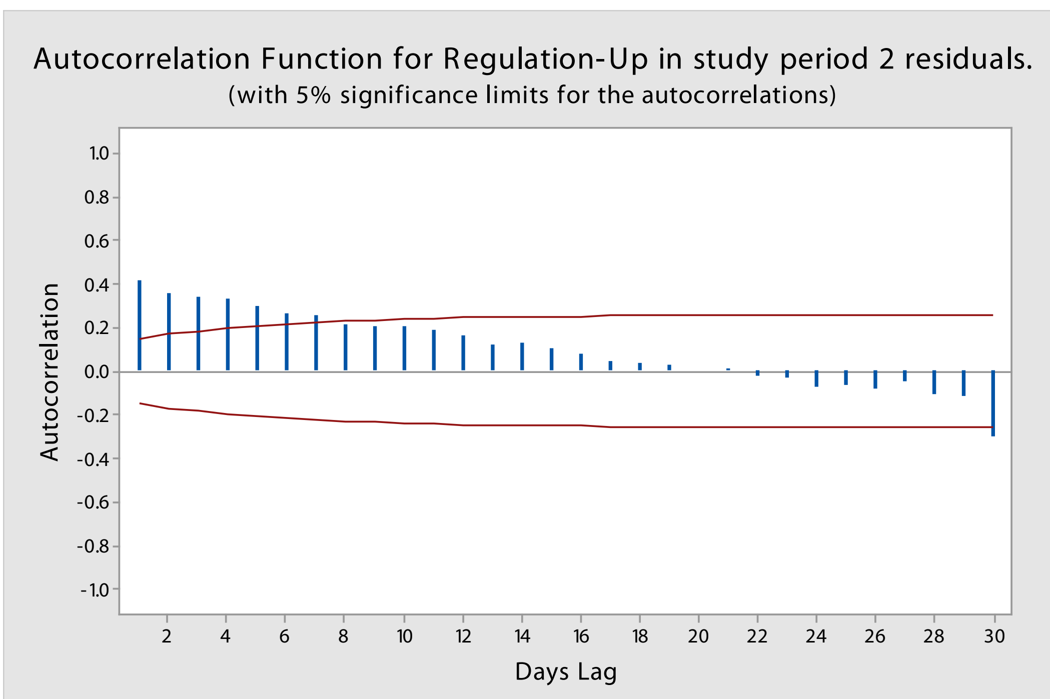


FIGURE 48

Residual Plots for Regulation-Down in study period 2 (with lags).

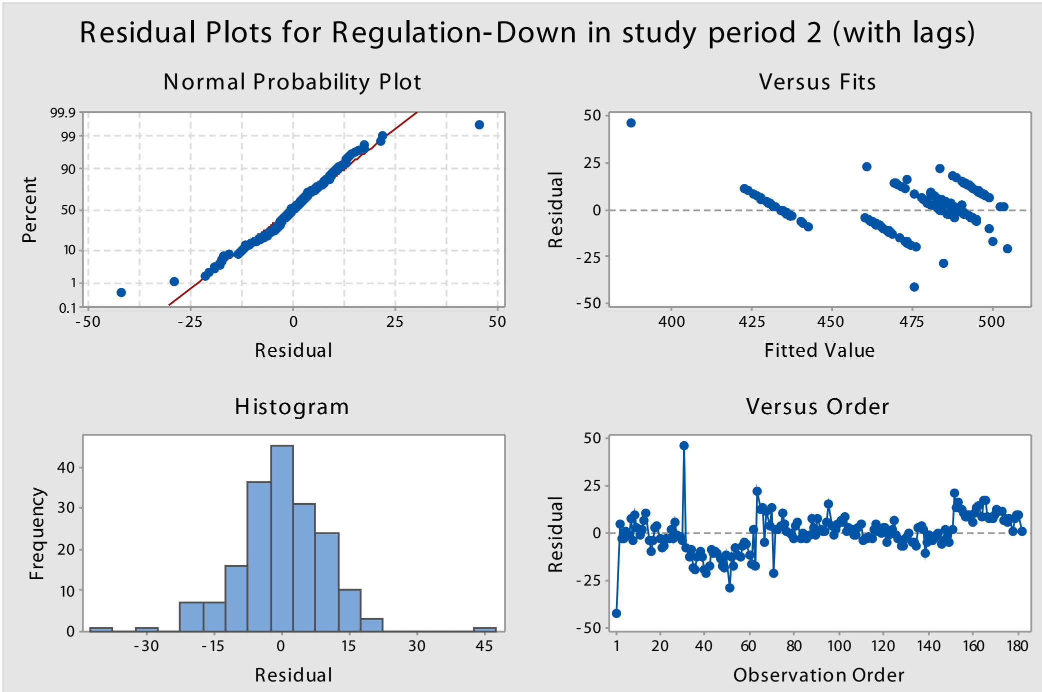


FIGURE 49

Autocorrelation Function for Regulation-Down in study period 2 residuals.

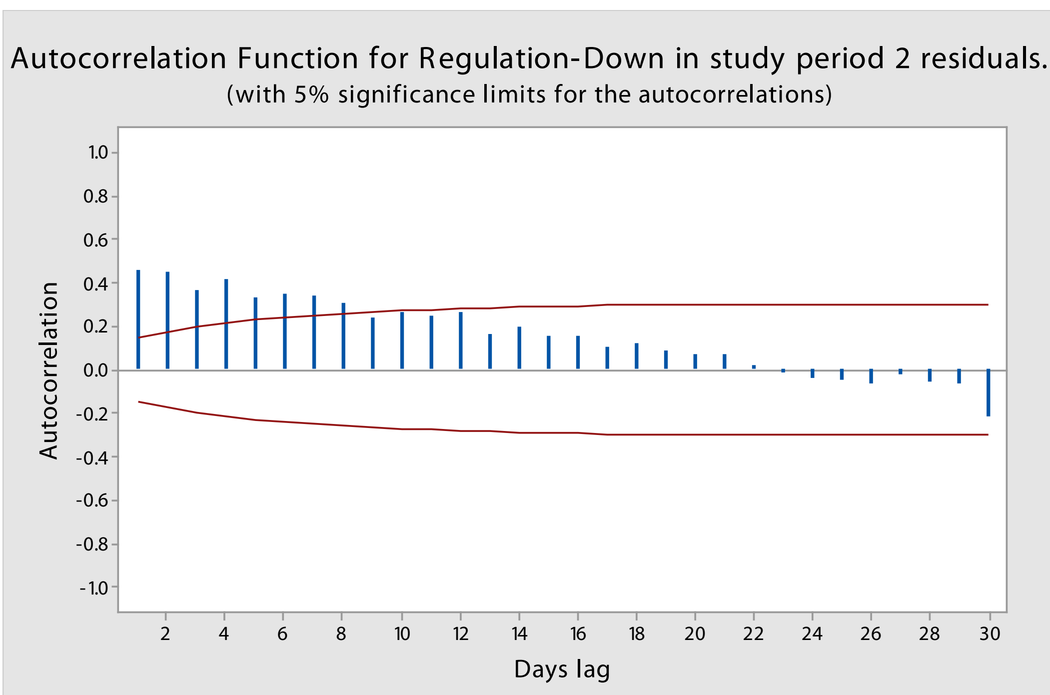


FIGURE 50

Residual Plots for Regulation-Up in study period 3 (with lags).

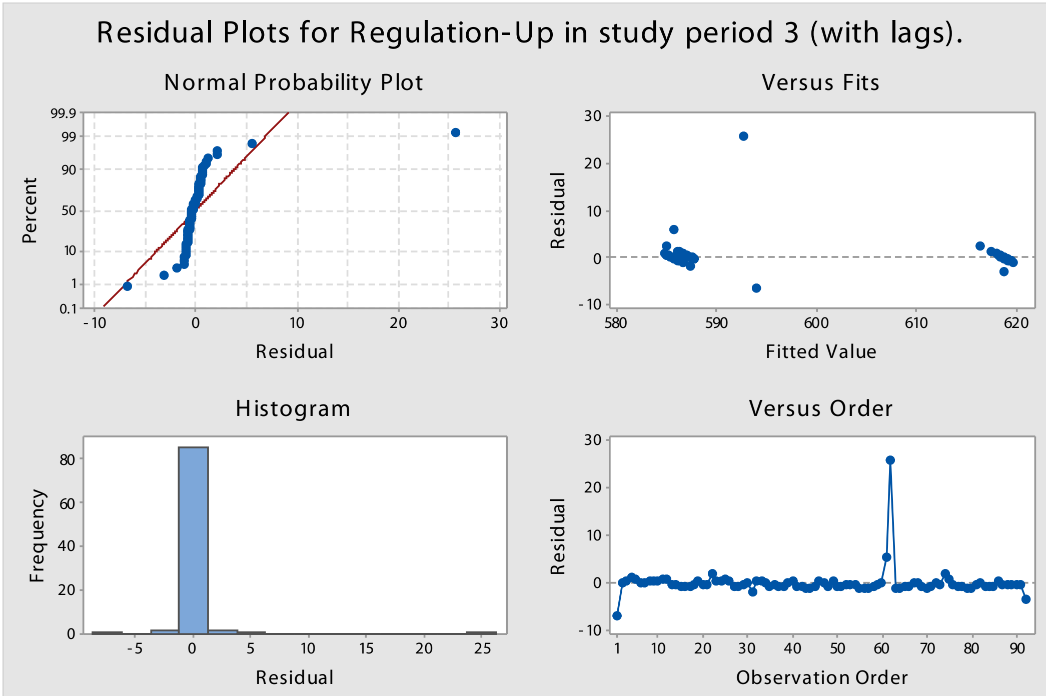


FIGURE 51

Autocorrelation Function for Regulation-Up in study period 3 residuals.

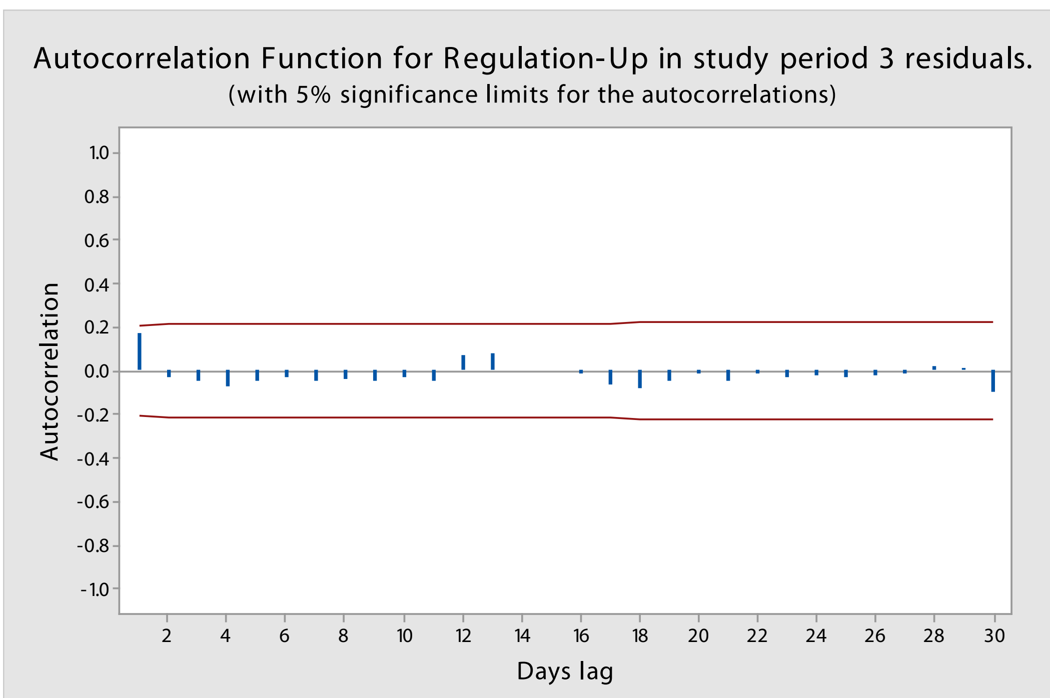


FIGURE 52

Residual Plots for Regulation-Down in study period 3 (with lags).

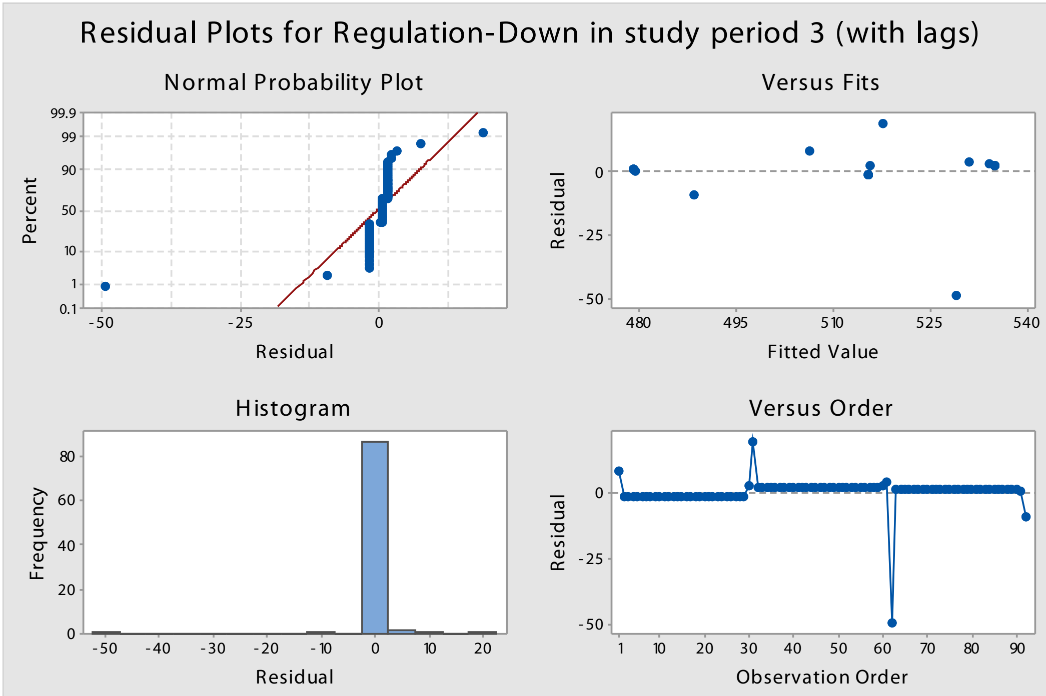


FIGURE 53

Autocorrelation Function for Regulation-Down study period 3 residuals.

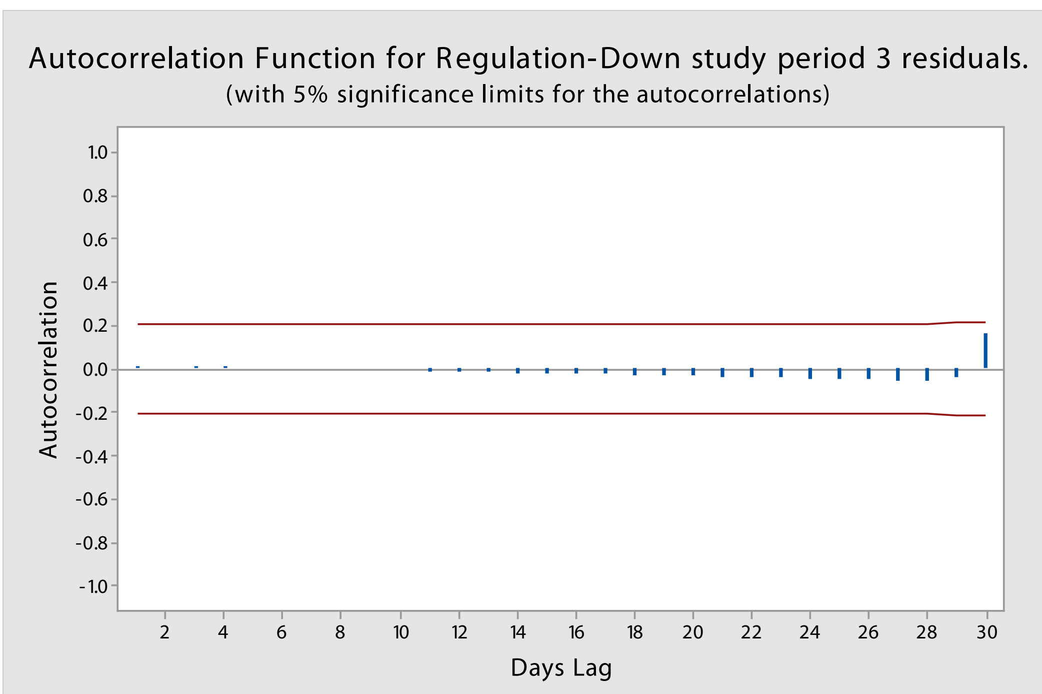


FIGURE 54

Residual Plots for Regulation-Up in study period 4 (with lags).

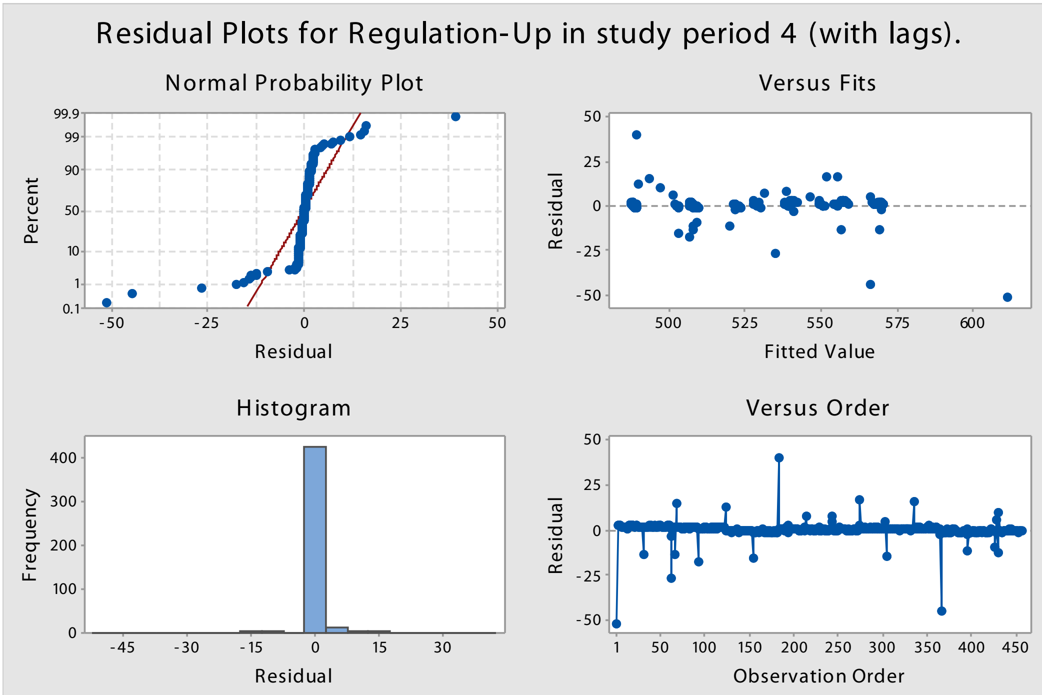


FIGURE 55

Autocorrelation Function for Regulation-Up study period residuals.

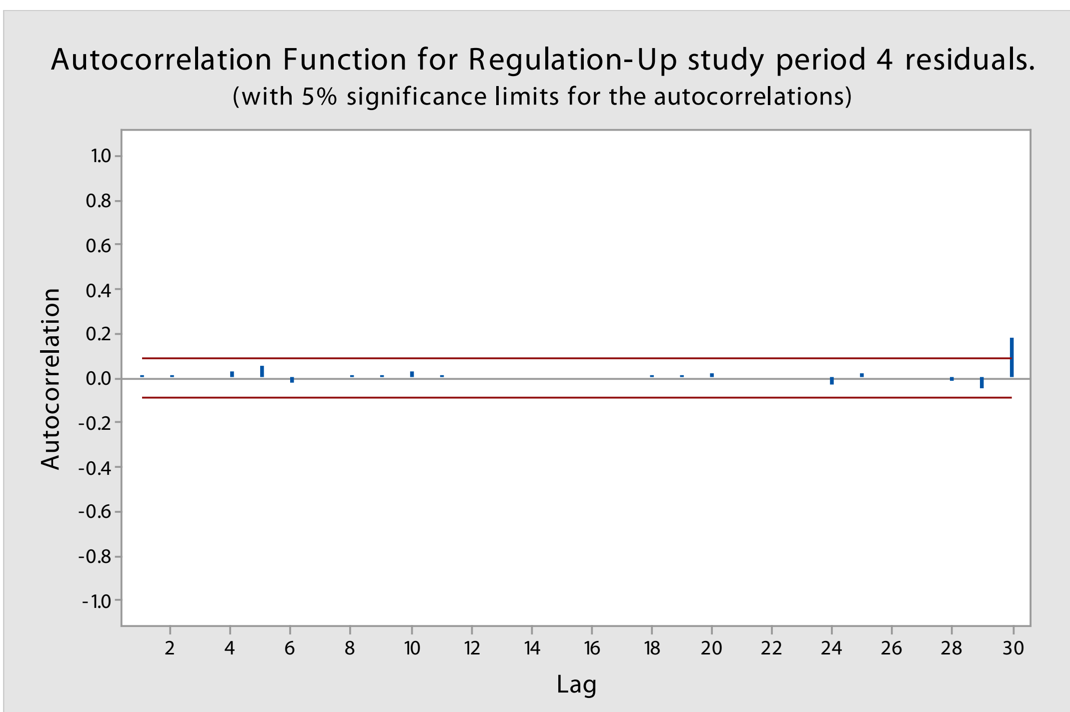


FIGURE 56

Residual Plots for Regulation-Down in study period 4 (with lags).

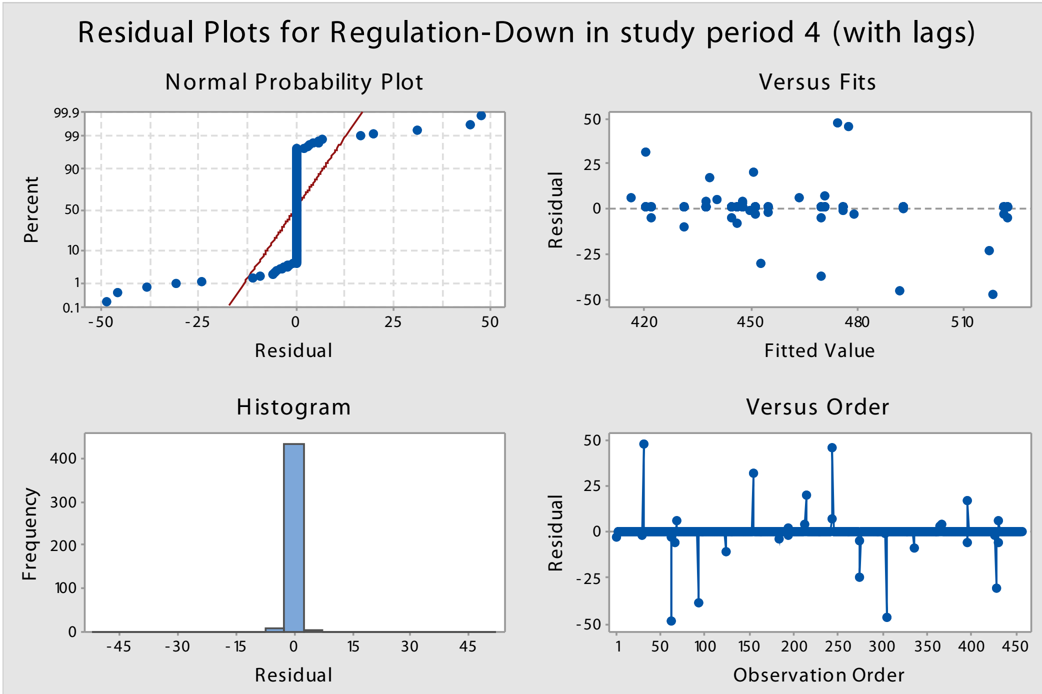


FIGURE 57

Autocorrelation Function for Regulation-Down study period 4 residuals.

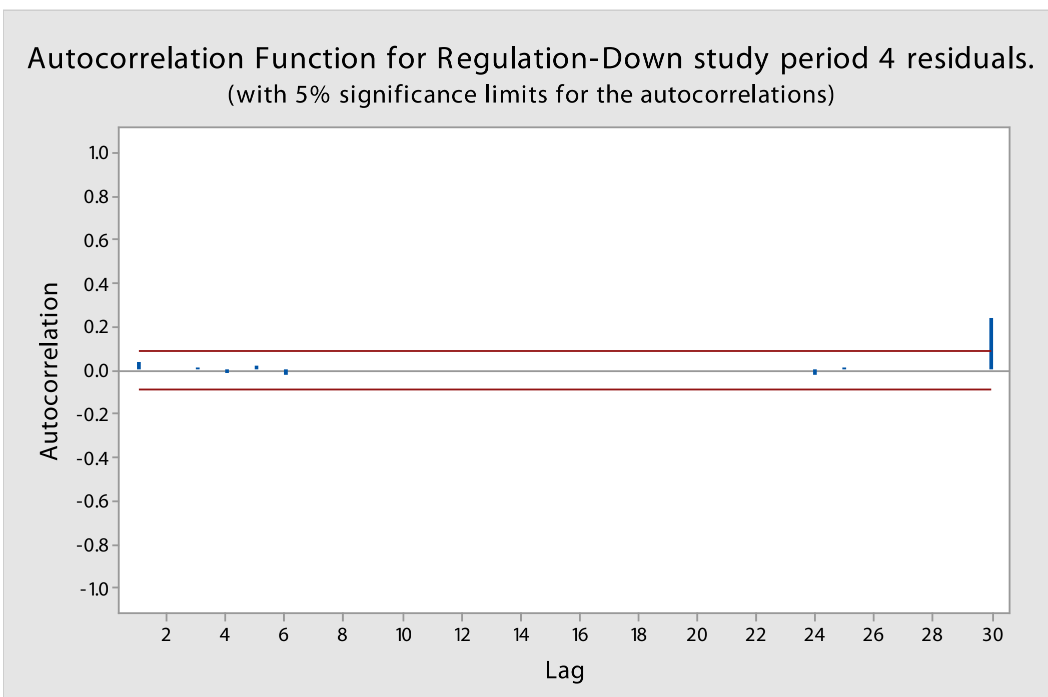


FIGURE 58

Residual Plots for Regulation-Up in study period 5 (with lags).

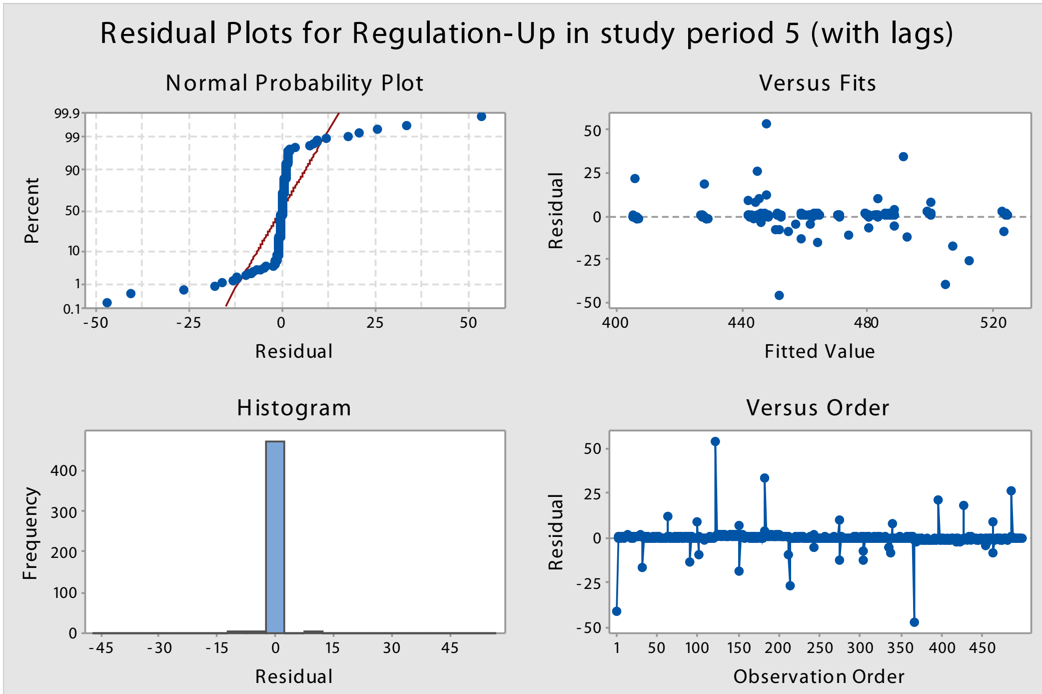


FIGURE 59

Autocorrelation Function for Regulation-Up period 5 residuals.

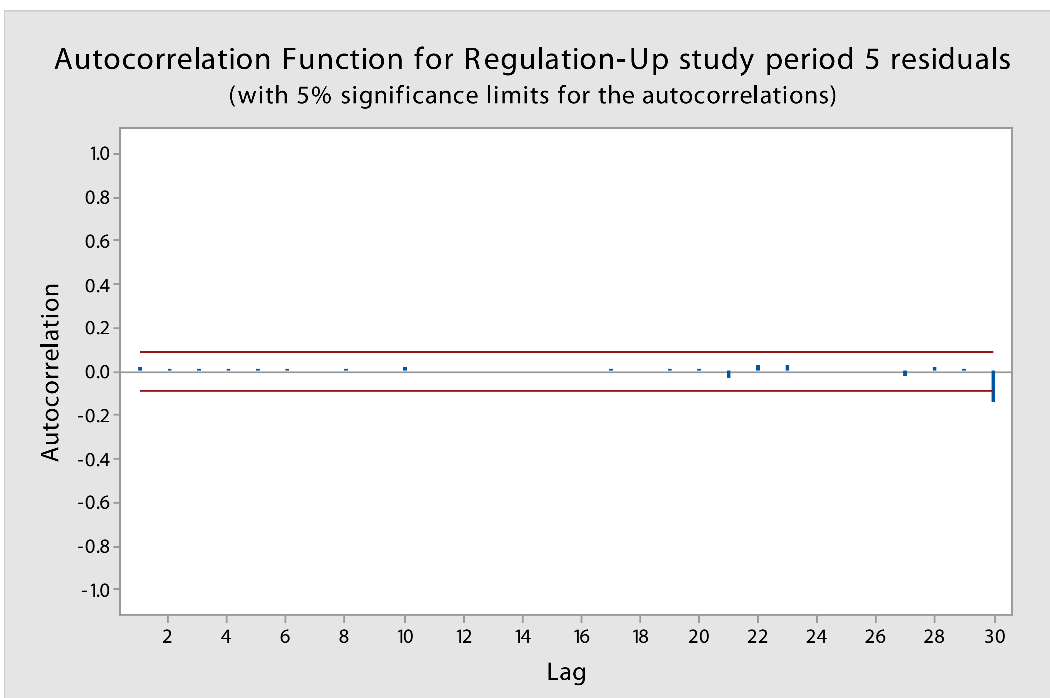


FIGURE 60

Residual Plots for Regulation-Down in study period 5 (with lags).

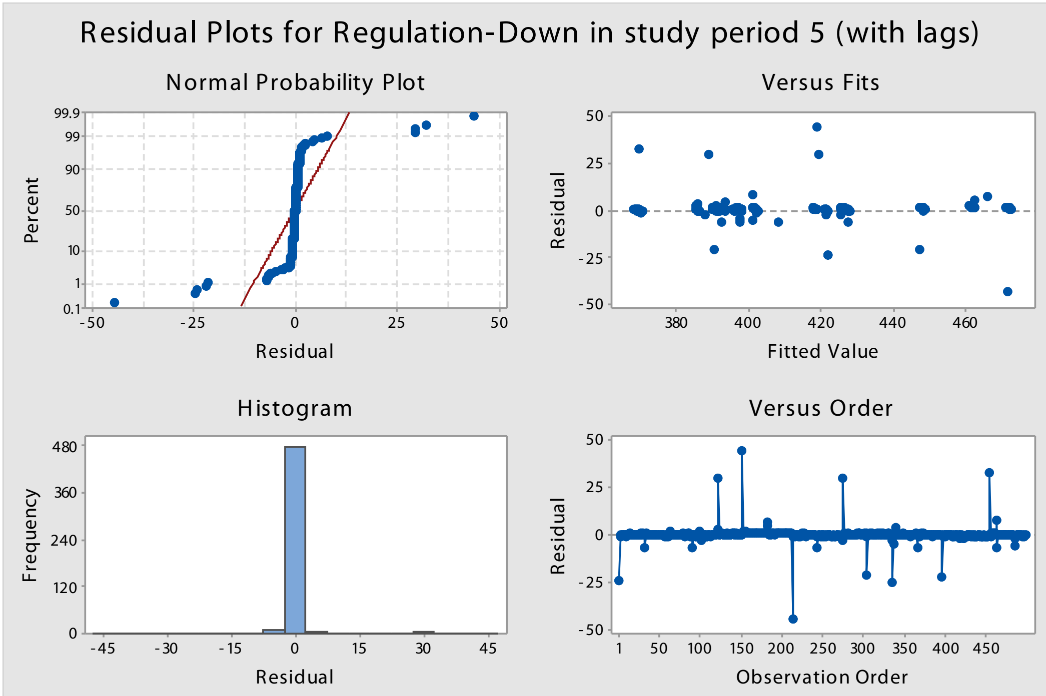
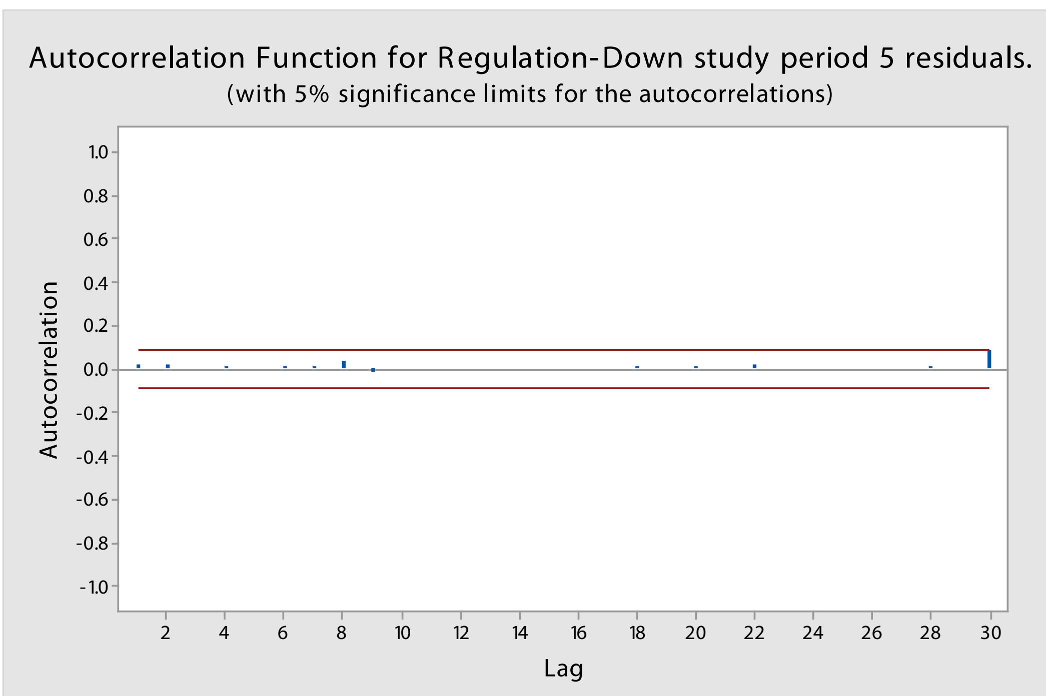


FIGURE 61

Autocorrelation Function for Regulation-Down study period 5 residuals.



CAUSATION ANALYSIS OF NETWORK PROTOCOLS REVISIONS WITH ANCILLARY SERVICES REQUIREMENTS

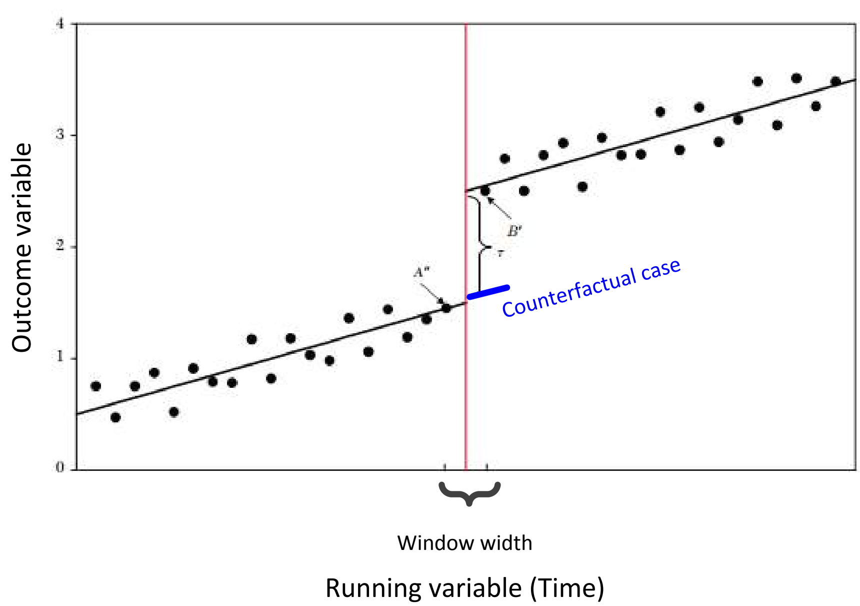
The previous section presented the development of regression models for required regulation-up and regulation-down ancillary services, which were tailored for each study period. Based on them, it is possible to support the claim that there is a correlation between ancillary services requirements, and demand, and installed wind power. Assuming that no significant protocol revisions occurred within the study periods identified, it can be considered that no change in operating reserves is due to NPRRs inside those periods, and all change is due to the effect of the NPPRs at the beginning of the respective study period.

In order to evaluate the impact of NPRRs, we consider AS procurement in the proximity of the effective date of a NPRR. It can be assumed that system conditions (i.e. installed power and demand) are practically similar just before and just after that date. Moreover, at each period transition, the same type and time resolution for reserves are presented. Thus, if there is a significant change in reserve requirements, it has to be due to the NPPR that defines the beginning of the study period. This observation causal inferences to be made about short-term effects and it is known in the literature as Regression Discontinuity Designs (RDD) [24], [25]

To illustrate how RDD works, let's consider the situation represented in Figure 62. The Figure presents the application of a policy change. Just before the change, it can be considered that the conditions at the point A are very similar to the ones at point B, which is after the policy. At left and right hand sides of the cut-off, regressions were obtained. If the regression obtained for the right hand side is extended somewhat to the right hand side of a small window, a counterfactual estimation can be obtained. In this case, if there is a significant difference between the counterfactual case and the real data, it means that the impact of the policy was significant at the cut-off. Notice that although the causation analysis is restricted to only the data points in the proximity of the cut-off, the distant data points impact on the regression function definition. However, in practical conditions the window size cannot be so small due to lack of data. Therefore, the impact of other variable (e.g. installed power and demand for this case) might start to be significant inducing a bias in the treatment effect of the policy. [25]

FIGURE 62

Illustration of RDD concepts.



For the particular problem of this report, and considering equations (9) and (10), the RDD experiment can be expressed mathematically in the following way:

(11)

$$\widehat{U_{p+1,t}} = U\acute{}_{p+1,t} + X_{p,p+1}\tau_{p,p+1},$$

(12)

$$\widehat{D_{p,t}} = D\acute{}_{p+1,t} + X_{p,p+1}\beta_{p,p+1},$$

where $U\acute{}_{p+1,t}$ and $D\acute{}_{p+1,t}$ represent the counterfactual estimations of the required regulation up and down reserves by using the regression model obtained for the time period p, $X_{p,p+1}$ a dummy variable that is equal one after the beginning of the period p+1, and $\tau_{p,p+1}$ and $\beta_{p,p+1}$ are the coefficients associated to the dummy variable for regulation up and regulation down.

The coefficients associated to each period-transition dummy variable and their significance are presented in Table 19. For window size it was considered 15 days before and 15 days after the cut-off. The significance and coefficients for other window sizes are also presented. From the results in the Table, it can be concluded that all the NPRRs changes considered in each period transmission produced significant changes in the amount of reserves procured just after the transition. Unfortunately, the conclusions obtained directly from RDD can only establish results for the short term. However, if we consider the regression coefficients associated to lags in the regression models presented in Tables Table

TABLE 19

Treatments effect for period transitions for required Regulation-Up and Regulation-Down reserves.

Period transition	Regulation - Up $\tau_{p,p+1}$			Regulation - Down $\beta_{p,p+1}$		
	Coefficient	p-value	Window size [days]	Coefficient	p-value	Window size [days]
1à 2	-326.12	0.000	10	-422.932	0.000	10
	-299.85	0.000	20	-425.448	0.000	20
	-272.27	0.000	30	-427.617	0.000	30
	-256.19	0.000	40	-429.346	0.000	40
2à 3	-1.90	**0.578**	10	10.16	**0.004**	10
	-3.99	**0.134**	20	11.79	0.000	20
	-4.79	**0.024**	30	11.83	0.000	30
	-7.09	0.000	40	12.98	0.000	40
3à 4	-55.05	0.000	10	-37.46	0.000	10
	-49	0.000	20	-49.93	0.000	20
	-45.25	0.000	30	-59.35	0.000	30
	-40.92	0.000	40	-66.56	0.000	40
4à 5	-45.829	0.000	10	-24.027	0.000	10
	-47.3	0.000	20	-23.672	0.000	20
	-48.032	0.000	30	-23.318	0.000	30
	-48.745	0.000	40	-22.964	0.000	40

10-Table 18, we can observe that these coefficients are very close to one. This means that if there is a change in the procured reserve value at the early beginning of a period (in which it is known that there was a significant change due to RDD), this change is propagated in the long-term due to the coefficient associated to lags.

In Table 19 are presented the coefficients and significance associated to the dummy variables used to represent the application of NPRRs. From these results, it is possible to rank the NPRRs according to their impact on terms of reserves requirements. In Table 20 and Table 21 are presented the NPRRs identified sorted according to their significance. It can be observed from Table 20 and Table 21 that the most significant changes in terms of regulation-up and regulation-down reserves required occurred during the transition from zonal to nodal market. In addition, it can be observed that the least significant was the NPRR352, which was related with the wind forecasting improvements.

TABLE 20

Sorting of NPRRs according to their impact on Regulation-Up procured reserves.

N	NPRR	Coefficient
1	NPRR045, NPRR050, NPRR210, NPRR214, NPRR239, NPRR258, and other zonal to nodal market changes	-272.27
2	NPRR460	-48.032
3	NPRR361	-45.25
4	NPRR352	-4.79

TABLE 21

Sorting of NPRRs according to their impact on Regulation-Down procured reserves.

N	NPRR	Coefficient
1	NPRR045, NPRR050, NPRR210, NPRR214, NPRR239, NPRR258, and other zonal to nodal market changes	-427.617
2	NPRR361	-59.35
3	NPRR460	-23.318
4	NPRR352	11.83

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