# An Ancillary Services Payment Mechanism for the Chilean Electricity Supply Industry*

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## Introduction

This report proposes an ancillary services payment mechanism for the Chilean electricity supply industry. This is accomplished in three steps. The first section presents a set of economic principles for assessing the likely performance of candidate ancillary services payment mechanisms in the context of Chilean electricity supply industry. The second section uses this framework to assess the likely performance of the ancillary services payment mechanism recently proposed by the National Energy Commission (NEC) in its letter Number 715 dated September 21, 2010. The third section formulates an alternative payment mechanism that respects the existing electricity market structures and rules in Chile, but is likely to provide lower cost and more reliable solution than the one proposed by the NEC. An appendix outlines several examples of how the proposed procurement mechanism could be implemented and how potential exercise of market power by a dominant supplier of any ancillary service could be mitigated.

## 1. Economic Principles for Assessing Ancillary Services Payment Mechanisms

There are a number of competing objectives that must be balanced in the design of an ancillary services payment mechanism. The major ones are: cost recovery for suppliers of ancillary services, least-cost supply of the required amounts of energy and each ancillary service, and maintaining an acceptable level of overall grid reliability. The goal of this report is to design an ancillary services payment mechanism that efficiently balances these objectives. "Efficiency" in this context means that the mechanism results in an outcome in which no objective can be improved without the deterioration of another objective. For example, for the three objectives listed earlier, it is not possible reduce the cost of procuring the required amount of energy and each ancillary service without either reducing the level of overall grid reliability or failing to achieve cost recovery for some ancillary services provider.

The Federal Energy Regulatory Commission (1995) in the United States defines 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." Ancillary services can be divided into three broad categories in order of decreasing responsiveness. The fastest responding ancillary service is Regulation Reserve. Units that provide this service must have equipment installed that automatically responds to signals from the system operator's energy management system (EMS) in real time to control the output of generation units and dynamic load resources within a prescribed area in response to a change in system frequency. The second most responsive ancillary service is Spinning Reserve, where a generation unit is on-line and able to produce additional energy within a pre-specified number of minutes. The final ancillary service is Non-Spinning Reserve, where the unit does not need to be on-line, but must still be able to provide additional energy within a pre-specified amount of time. Voltage support and black start are also typically classified as ancillary services. However, in most re-structured electricity supply industries, these services are procured through either a long-term procurement process or through a cost-of-service regulatory process. Section 3 describes how the basic proposed procurement mechanism can be expanded to incorporate these two services.

Aspects of how generation units provide ancillary services and system operators utilize them argue in favor of a payment mechanism based on the services provided and not what specific generation unit or generation technology provides the service. Generation technologies differ in terms of their ability to provide certain ancillary services. By designing a payment mechanism to purchase the service desired by the system operator (rather than the right to call upon a specific generation unit), all resources can be appropriately compensated for the services they provide. For example, hydro units with reservoirs are typically better able to provide regulation reserve than thermal units, because they usually have larger ramp rates than thermal units. In addition, from the system operator's perspective, a more of a more responsive ancillary service can be used place of a less responsive one. For example, if more Regulation Reserve is available that is necessary; the surplus can be used to reduce the system's Spinning Reserve requirement. The ancillary services payment mechanism should allow for this possibility.

Designing an ancillary services payment mechanism is complicated by the fact that only a small portion of the costs of providing an ancillary service is directly related to the quantity of the ancillary service provided. The vast majority of the direct costs of providing an ancillary service do not vary with the amount of the product provided. For example, the most significant direct cost associated with providing Regulation Reserve is the up-front cost of the equipment necessary to communicate with and respond to the system operator's EMS. Generation unit owners providing Regulation Reserve are compensated for the amount the energy they produce while providing this service through the hourly energy market, so the additional cost of providing net energy within the hour is not a direct cost associated with this ancillary service. Generation unit owners providing non-spinning reserve incur no direct volume variable cost associated with providing this service. For example, a 240 megawatt (MW) generation unit providing 50 MW of Spinning Reserve does not incur any additional direct costs with providing 51 MW of Spinning Reserve.

Although it is unlikely that there are significant direct volume-variable costs associated with providing any of the above three ancillary services, often there is an opportunity cost associated with providing each of these products. For example, a generation unit providing Spinning Reserve is unable to sell energy from the unloaded generation capacity providing this ancillary service. If the generation unit's operating cost is less than the market-clearing price of energy, then the difference between the market-clearing price of energy and its operating cost is that unit's opportunity cost of providing the ancillary service. Hydroelectric units can also have an opportunity cost of providing ancillary services. For example, if the value of water for a hydroelectric generation unit during that hour (the opportunity cost of consuming water for the last MWh it produces during that hour) is less than market price during that hour, the difference between the market-clearing price and the unit's value of water is the opportunity cost of providing the ancillary service.

Although there is a theoretical possibility that a hydroelectric unit will have a value of water for the last MWh produced that is less than the market-clearing price for the hour, there are unlikely to be many hours when this circumstance will exist. For example, one might think that a hydroelectric unit would have a positive opportunity cost of providing an ancillary service if transmission constraints prevent it from selling as much water as it would like. However, this generation unit also has a lower value of water because of these transmission constraints. Unless the market-clearing price at its location is greater than its value of water, there would be not be a positive opportunity cost of this unit providing ancillary services even though it is selling water at a lower price than hydroelectric units located outside of this congested area.

In general, the only time a hydroelectric or thermal generation unit would have positive opportunity cost of providing an ancillary service is if it would prefer to be selling additional energy at the prevailing market-clearing price for that unit as opposed to providing an ancillary services. If a thermal unit has a variable cost of producing energy above the market-clearing price at its location, then the opportunity cost of providing ancillary services from that unit is zero. Similarly, if a hydroelectric unit has a value of water above the market-clearing price at its location, then the opportunity cost of providing ancillary services from that unit is zero.

There are also likely to be additional costs associated with the number of hours that a unit provides a given ancillary service, rather than with the MW quantity of a given ancillary service provided within an hour. For example, a generation unit that provides more hours of Regulation Reserve is likely incur more wear and tear or incur more forced outages, both of which require more annual operating and maintenance expenditures, than a unit that sells the same amount of energy annually, but sells Regulation Reserve during fewer hours in the year.

How the total cost of providing each ancillary service are incurred by generation unit owners and participating dynamic load resources makes the design of an ancillary services payment mechanism particularly challenging. Economically efficient pricing implies setting the hourly market price of each ancillary service equal to highest direct marginal cost (which is close to zero) plus the opportunity cost of providing that service (which can equal zero for the reasons described above) needed to meet the demand for that service. However, this may not yield sufficient revenues for the providers of these services to recover their total costs on an annual basis. This implies that deviations from economically efficient pricing may be necessary in order to achieve the goal of cost recovery for each generation unit providing ancillary services.

This desire for efficient pricing of ancillary services yields our first principle.

*Principle 1: The hourly price paid to each ancillary service should at least equal the sum of both the direct variable cost and opportunity cost of the resource providing that ancillary service.*

This principle allows different hourly prices to be paid to each ancillary service at different locations in the transmission network if the market for an ancillary service becomes segmented because of the configuration of the transmission network or other local operating constraints. Principle 2 deals with how annual generation unit-level revenue shortfalls should be recovered to minimize the distortions from efficient pricing.

*Principle 2: Annual generation unit-level revenue shortfalls from selling ancillary services in the short-term market should be recovered through an annual fixed payment to that resource owner, rather than by ad hoc increases in the hourly price of ancillary services.*

This annual revenue shortfall is the sum of total hourly ancillary services revenues for the year less the total fixed and variable costs associated with providing ancillary services over that same time period. These costs should also include any additional costs to sell energy or ancillary services out of merit order because of local transmission or reliability constraints only to the extent that these costs are not paid through other mechanisms. For example, if a generation unit is required to operate because of local transmission or reliability constraints and it has a variable cost or value of water higher than the prevailing market-clearing price at its location, then if the unit owner is not compensated for this cost different in the energy market, the difference between the unit's variable cost and the market-clearing price times the amount of energy produced that hour should be including in this annual total cost figure.

Setting a higher hourly price for an ancillary service in order to provide additional revenues to certain generation unit owners may over-compensate other generation unit owners and encourage more generation unit owners than are necessary to make the investments needed to provide this ancillary service. Generation unit owners may also distort their capacity availability declarations to the system operator in order to increase the revenues they receive for providing ancillary services from other generation units in their portfolio. These two actions would require consumers to pay more than is necessary for the ancillary services they consume on an annual basis.

In order to minimize the amount that consumers ultimately pay for the provision of the energy and ancillary services necessary to maintain a reliable supply of electricity, the ancillary service payment mechanism should provide incentives for generation unit owners to provide these services at the lowest total annual cost. Moreover, the units with lowest direct variable cost and opportunity costs should provide a larger share of these services. This yields our third principle.

*Principle 3: The mechanism used to determine which resources provide ancillary services and payments made to the resources providing ancillary services should provide economic incentives for the least cost supply of energy and ancillary services to final electricity consumers.*

An immediate implication of this principle is that the energy and ancillary services requirements for all generation units should be simultaneously determined. This is the only way to ensure that each generation unit is being used in a least-cost manner to satisfy the system-wide demands for energy and ancillary services. Currently, the Load Economic Dispatch Center (CDEC) of the Central Interconnected System (SIC) does not simultaneously determine which generation units provide energy and ancillary services. However, doing so should not significantly complicate the existing dispatch process.

The final principle deals with the definition of the set of resources able to provide each ancillary service. Different generation and dynamic load resource technologies can provide each type of ancillary service. For example, Regulation Reserve is often supplied by both hydroelectric and thermal generation resources, and even dynamic load resource technologies such as large-scale batteries.

*Principle 4: The system operator should define the technological characteristics of each ancillary service necessary to operate the transmission network, and allow all generation and load resources able to provide that ancillary service the opportunity to compete to provide it.*

This principle is reinforces Principle 3, because it maximizes the set of available resources able to compete to provide each ancillary service and thereby reduces the cost to final consumers of providing both energy and ancillary services. Although there are three distinct ancillary services—Regulation Reserve, Spinning Reserve, and Non-Spinning Reserve—all units that are capable of providing each ancillary service should have the opportunity to provide that service in the short-term market. For example, if a unit is capable of providing all three ancillary services, it should be allowed to make capacity offers for each of these services to the CDEC. However, because more responsive ancillary services can substitute for less responsive ancillary services, if a unit owner offers capacity to supply Regulation Reserve this capacity can be used to reduce the hourly demand for Spinning and Non-Spinning reserve, if it is economic to do and if the total capacity offered to provide Regulation Reserve is greater than the hourly system demand for that ancillary service.

## 2. Review of NEC Ancillary Services Payment Proposal

This section assesses the properties of the NEC ancillary services proposal relative to principles guiding the design of an efficient ancillary service payment mechanism developed in the previous section. Aspects of the NEC proposal are inconsistent with several of these principles. This implies that there are modifications to the proposal that could reduce the cost of procuring the necessary ancillary services without reducing overall system reliability or failing to achieve cost recovery for ancillary services providers. An ancillary services proposal that addresses many of the deficiencies in the NEC proposed is described in Section 4.

The NEC proposal requires that CDEC determine which ancillary services are to be provided. These services currently include: (1) voltage control, (2) operating reserves--Regulation, Spinning, and Non-Spinning Reserves, and (3) black start. CDEC then sets the requirements for the year for each of these ancillary services. Next, CDEC determines which market participants—generation unit owners, transmission network owners, electricity distributors, and final consumers—need to install the equipment necessary to deliver each ancillary service. Orders to specific market participants to install the equipment necessary to provide these services will be issued each year by CDEC, although CDEC also has the option to issue additional orders for these investments to be made within the year. The NEC proposal requires that all generation units that CDEC has certified to provide a service to offer it into the short-term market.

CDEC determines the aggregate hourly requirement for each ancillary service and then allocates these hourly requirements to each generation unit eligible to provide each service. Generation unit owners that are in deficit relative to their requirement can buy this service from market participants that supply more than their requirement. Market participants are entitled to recover the investment cost for the equipment ordered by CDEC, the annual maintenance cost for this equipment, and any additional fuel costs associated with providing the ancillary service.

The NEC proposal determines the short-run variable cost of providing spinning reserve from a generation unit as the opportunity cost of providing energy from that generation unit. Specifically, the NEC proposal defines the opportunity cost of providing spinning reserve as the difference between the hourly system price minus the variable cost of that generation unit. CDEC has the discretion to determine how the three costs associated with the provision of ancillary services from a generation unit—investment costs, maintenance costs, and additional fuel costs—are recovered during each operating period. These additional fuel costs are primarily caused by the uneconomical operation of the generation unit because local reliability constraints require operating a generation unit that has a variable cost above the relevant market-clearing price for that unit.

Under the NEC proposal, CDEC also determines how each generation unit will be charged for ancillary services shortfalls or paid for ancillary services surpluses from each generation unit. The NEC proposal allocates these costs to generation unit owners according to their share of total energy injections to the transmission network during the month. Finally, the NEC proposal allows electricity retailers, distribution companies, or large customers not subject to retail price regulation to provide automatic load shedding services and be compensated for each megawatt-hour (MWh) of load reduction at a value of loss load (VOLL) that is substantially less than cost of shortage used in the dispatch algorithm. The NEC proposal allows CDEC to specify the total amount of automatic load shedding services needed. CDEC also has the ability to order customers to install the equipment necessary to provide these services. According with the NEC proposal, customers will be compensated if the volume of energy in KWh or time disconnected in hours exceeds the levels allowed by NEC proposal. The compensation is based on the short-term value of lost load (VOLL) for each MWh not supplied above the level set in the proposal.

There are a number of shortcomings of the existing NEC proposal relative to the principles outlined in the previous section which are likely to increase unnecessarily the total cost ultimately paid by Chilean electricity consumers for energy and ancillary services. First, the NEC proposal requires that the CDEC designate which agents: generation units, transmission facilities, distribution facilities, or final electricity consumers, must install the necessary capital equipment to provide each ancillary service and guarantee full cost recovery for the agents providing ancillary services. This approach is inconsistent with Principle 4 which argues that CDEC should designate the ancillary services that it would like to procure and allow all resources to compete to provide these services.

One way to address this shortcoming would be for CDEC to run an annual procurement process for the resources necessary to provide each ancillary service. Generation and load participants would bid a $/MW-year amount that they are willing to be paid to make a pre-specified amount of MW of each ancillary service they could provide available to the system operator each hour for an entire year. This procurement process could be run using a market-clearing price mechanism. If there are locational requirements for an ancillary service, CDEC could run separate procurement processes for each location. The results of this procurement process would yield specific MW quantities of each ancillary service that must be offered to CDEC each hour of the year. The winners in the auction need not provide these each ancillary service MW they won from the same resource each hour of the year. Instead, for each of the hour of the year, they must provide at least the amount of each ancillary service capacity that they committed to provide from resources that are certified by CDEC to provide that service, or be subject to a substantial non-performance penalty.

This procurement process would simultaneous purchase the annual commitments for each of the designated ancillary services. Under this mechanism, agents sell commitments to provide a fixed quantity of capacity certified by CDEC to able to provide that ancillary service each hour of a pre-specified time period. Entities selling these commitments may, but are not required, to own the physical resources that allow them to provide the ancillary services commitments sold. However, there is no requirement that a seller always satisfies its ancillary services commitments only using resources it owns. Sellers of these commitments are allowed to use certified capacity owned by other market participants to satisfy these commitments. The option to use resources owned by other market participants should result in lower total annual procurement costs for all ancillary services, if the secondary market for these services is not subject to the exercise of substantial unilateral market power.

The advantage of this approach to procuring the necessary ancillary services-capable resources is that it provides strong incentives for the least-cost supply of all of the ancillary services that CDEC determines are necessary each hour of the day. The supplier of these commitments to provide each ancillary service capacity is free to offer different resources to CDEC at different times throughout year, as long as the resource is qualified to provide that ancillary service set by CDEC. This flexibility should significantly reduce the cost of providing the necessary ancillary services to the Chilean electricity supply industry. This approach would also eliminate the need for suppliers of these services to make cost-of-service filings with CDEC. Providers of each of these products would receive a product-specific and location-specific hourly market-clearing price. This would further increase the incentives for suppliers to reduce the cost of providing the necessary ancillary services for reliable system operation, because the supplier has no financial interest in increasing the costs of supplying these services in order to receive higher revenues, as would be the case under the NEC proposal which promises them full cost recovery.

Another shortcoming of the NEC proposal is that it does not require that CDEC co-optimize energy and ancillary services procurement and set an hourly price for each ancillary service based on the marginal cost of meeting that ancillary service need on a system-wide basis, which is also inconsistent with Principles 1 and 3. Ideally, CDEC should use the resources made available to it to provide energy and ancillary services to minimize the total variable cost of meeting the system-wide demand for energy and each ancillary service. In this way, the CDEC will efficiently trade off the cost of using a resource to meet the demand for energy versus the demand for each ancillary service that it is capable of providing. Co-optimization also provides a mechanism for setting an hourly price for supplying each ancillary service. In particular, the increase in the total cost of procuring both energy and ancillary services associated with a 1 MW increase in the demand for that ancillary service would be the hourly price paid to the supplier of that ancillary service. This approach to setting the hourly price of each ancillary service is consistent with Principle 1.

Determining the amount of energy and ancillary services to be taken from each generation unit using this joint optimization process would be consistent with the Principle 3, because it would find the least cost way to use each resource to meet the system's energy and ancillary services requirements. NEC proposal does not involve solving this joint optimization problem to determine resource-level energy and ancillary services supplies. Instead, CDEC first dispatches generation units to meet the demand for energy and then allocates the demand for operating reserves among the units dispatched.

The NEC proposal also allows for the possibility that the hourly prices for each ancillary service can be in excess of the system-wide marginal cost associated that ancillary service. Setting an hourly price for an ancillary service that is higher than the system marginal cost for that service can encourage suppliers that are not the least-cost providers of that service to sell it. In addition, because of how the total cost of ancillary services are recovered from all generation unit owners under the NEC proposal, setting too high of an hourly price for an ancillary service can cause higher cost suppliers of ancillary services to provide them to CDEC from their own units in order to avoid having to pay the higher hourly price of ancillary services provided by a lower cost supplier of that ancillary service.[1]

Assigning the cost of procuring ancillary services to generation unit owners and allowing them to self-supply their ancillary services obligation as described in the NEC proposal can create the incentive for higher cost units to self-supply their ancillary service obligations. Because CDEC determines the aggregate demand for each ancillary service and the assignment of ancillary services obligations to individual generation units is not precisely specified, it is unclear what market efficiency benefits might result from assigning these obligations to individual generation unit owners, even though the potential market inefficiencies introduced by this allocation are clear.

Because electricity consumers ultimately pay for the total cost of the energy and ancillary services they consume in retail electricity prices, by assigning these costs to generation unit owners the NEC proposal is likely to increase the incentives for deviations from the least-cost supply of energy and ancillary services by resource owners attempting to avoid being assigned ancillary services costs. For these reasons, assigning all of these costs to electricity consumers is more likely reduce aggregate energy and ancillary services costs final consumers than charging these costs to generation unit owners and then relying on them to pass these costs on to final electricity consumers.

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[1] Recall that the NEC proposal requires all the units that are dispatched by the CDEC to participate in providing reserves. At the end of each month, CDEC determines each generation unit's deficit or surplus in the provision of each ancillary service. Units in deficit for their reserve requirements pay units that provided more than their obligation.

Nevertheless, under the SIC rules, customers cannot participate in the short-term market. Generation unit owners buy energy from the short-term market, at system-wide marginal cost, in order to fulfill their energy commitments to retailers. Therefore, under the current SIC rules generation unit owners must buy ancillary services from the short-term market. It is important to emphasize that generation unit owners with supply contracts to regulated retailers (distributors), receive an extra charge in the node price (regulated wholesale energy price in $/MWh) based on voltage quality and the value of the system-wide reserve margin. Therefore, under the current SIC rules, generation unit owners collect revenue from their customers to pay for the ancillary services the unit owner procured in the spot market.

A final shortcoming of the NEC proposal is the difference between the price paid to curtailed demand versus the shortage price used in the CDEC dispatch algorithm. Specifically, generation unit owners must pay suppliers of curtailed load $US 3240/MWh in the SIC and $US 4860/MWh in the SING (Northern Interconnected System), whereas the current shortage price used by CDEC in the short-term market (also used by the NEC to calculate the regulated node price each six months) to determine the opportunity cost of water in the SIC is $US 490/MWh and $US 335MWh in the SING. This creates an inconsistency between the how the system is operated to conserve water, in the case of the SIC, and what generation unit owners must pay when demand is curtailed. In the SIC, the dispatch algorithm assumes the payment for curtailed load is roughly 1/6 value that it actually is. This divergence between the two prices implies that hydroelectric resources are used far more intensively than would be the case if the scarcity price was set to the amount that generation unit owners must pay for curtailed load. In addition, this divergence also implies that energy prices are lower than would be the case if the scarcity price was set at $US 3240/MWh. Finally, this divergence between the two prices implies that scarcity conditions are more likely to occur, even though generation unit owners have a strong incentive for them not to occur because of the substantial payments they must make to curtailed load.

This divergence between the two prices can be corrected by reducing the price that must be paid to curtailed load or increasing the scarcity price used in the algorithm used by CDEC to determine the opportunity cost of water. The former approach would significantly reduce the amount final consumers willing to provide load reductions, which would increase the challenges that CDEC would face in managing supply shortfalls. The latter approach would tend to raise wholesale energy prices, particularly during low water periods, but it would have benefit of reducing the likelihood that supply shortfalls occur and incent more final consumers to provide demand reductions when water shortfalls ultimately occur.

## 3. Proposed Ancillary Service Payment Mechanism

This section outlines an alternative ancillary services payment mechanism that addresses the inconsistencies between the NEC proposal and the four principles described in Section 2. This mechanism is consistent with the cost-based short-term energy market among generation unit owners and the long-term contract market for energy between generation unit owners and regulated retailers (distributors) or industrial customers that currently exists in Chile.

Under this proposed payment mechanism generation unit owners would receive two forms of compensation for providing each ancillary service. The first would be an annual MW-year payment or monthly MW-month payment for making a pre-specified quantity of certified (by CDEC) ancillary service capacity available to CDEC each hour of the day during that time interval. The seller of this product would be free to substitute different resources for this available capacity, as long as these resources were qualified by CDEC to provide these ancillary services. For example, a market participant might sell 100 MW of spinning reserve capacity in the annual commitment auction. Then during each hour of the coming year, that market participant would be required offer to CDEC 100 MW of spinning reserve capacity from a resource that is qualified by CDEC to provide that ancillary service. Note that this requirement to offer spinning reserve capacity does not imply that this capacity will be taken by CDEC to provide spinning reserve during that hour. Whether that occurs depends on the level of demand, the amount and location of available generation capacity, and the ancillary services requirements set by CDEC for that hour.

The market mechanism used to purchase this operating reserve capacity could also operate on a monthly basis rather than just on a yearly basis if there is concern that less reserve-capable capacity is needed during different months of the year. In addition, the ancillary services products could also be defined locationally if there is concern that ancillary service capacity purchased for one location cannot be used throughout the transmission network. To provide strong incentives for the least-cost supply of ancillary service-capable capacity, all providers should receive the same market-clearing price for each MW of ancillary service commitments they provide. This ensures that a market participant's revenue stream is fixed for the year or month at the product of the market-clearing price and the MWs of capacity sold in the auction, which implies that a profit-maximizing supplier of this product has the strongest possible incentive to find the least cost source of supply of available ancillary services capacity from the set of qualified resources each hour of the commitment period.

To support this aspect of the payment mechanism, the CDEC must have clearly elaborated technical specifications that resources must satisfy for each of the ancillary services products and have a process for certifying actual physical resources as being able to provide these products. This certification process must operate continuously throughout the year because different resources may be lower cost suppliers of these products at different times of the year. For example, during a time period with water levels near capacity, hydroelectric units are poorly suited to provide operating reserves, so thermal units may be lower cost sources of supply, despite the fact that under normal system conditions the opposite is true.

The second part of the payment mechanism is a short-term hourly price for each ancillary service based the least-cost dispatch of generation units to meet the system-wide demand for energy and ancillary services. CDEC would dispatch the system based on the variable cost of producing energy from generation units, the opportunity cost of water from hydroelectric facilities, and any verified (by CDEC) volume-variable cost (a cost that varies with the number of MWs provided by the actual resource offered to provide that service during that hour) associated with providing each ancillary service that a resource is capable of providing.

As discussed in Section 2, it is unlikely to be the case that the direct variable cost associated with providing any ancillary service is significantly different from zero, but it also difficult to argue that these costs are zero for the reasons discussed in Section 2. Nevertheless, CDEC should set a high standard for the verified volume-variable cost for a resource providing a given ancillary service. It is important that the specifications of the ancillary services products allow both generation resources and load resources to compete to provide these products.

The variable costs of producing energy that generation unit owners submit to CDEC should reflect the fact that the marginal cost producing energy from a generation unit varies with the level of output from that generation unit. A more realistic modeling of the variable cost producing energy from fossil-fuel generation units in the dispatch and pricing model used by CDEC will ensure that the system's energy and ancillary services needs are in fact supplied in a least cost manner. For example, a dispatch model that recognizes that the marginal cost of producing energy from a fossil fuel units rises as the output of the unit nears or exceeds the nameplate capacity of the unit will find it least cost to supply ancillary services from a mix of generation units rather than supplying those products from a small number of resources. This point reinforces the basic point that satisfying energy and ancillary services demands through a co-optimization process requires a more accurate model of the variable costs of producing energy from each generation unit in order to ensure that the results of the short-term market yields a configuration of generation unit output levels and ancillary services quantities that is least-cost for the actual operation of the system.

In all wholesale markets in the United States, generation units are allowed to submit energy offer curves with multiple steps to the short-term market. For example, in California each generation unit owner can submit up to ten offer price and offer quantity pairs up to the nameplate capacity of the unit in both the day-ahead and real-time markets. In addition, as part of the local market power mitigation mechanisms in United States markets, fossil fuel generation unit owners are also required to submit heat rate curves to the system operator. These heat rate curves have multiple steps up to the capacity of the generation unit. The heat rate curve is used to construct a generation unit's revised offer curve when system operator's local market power mitigation mechanism subjects its submitted offer curve to mitigation. In California, these heat rate curves are piece-wise linear functions with up to ten linear segments up to the capacity of the generation unit. These curves are also not required to be upward sloping to allow for the fact that heat rates may not be monotonic in the output level of the generation unit. More flexible cost-based offer curves similar to those used in United States markets could be introduced into the CDEC, with the benefit of yielding a dispatch of energy and ancillary services from all generation units that is more representative of the actual cost of providing these services.

The short-term energy and ancillary services dispatch process should pay market-clearing prices for suppliers of ancillary services equal to increase in the minimized objective function value associated with increasing the ancillary service product demand by one unit. By paying a market-clearing price to all resources providing ancillary services during that hour, resource owners have an incentive to find the least cost supply of these ancillary services on an hourly basis. This conclusion follow from the logic that if a market participant finds a lower-cost resource to offer into the short-term market and this does not change the market-clearing price, then that market participant will earn higher profits as a result. These short-term market prices can also be set locationally if CDEC has locational ancillary services requirements and imposes these constraints in the dispatch and pricing model.

An important benefit of this proposal is that there is no need for CDEC to order suppliers to install the capital equipment needed to supply an ancillary service or verify anything but the short-run volume-variable costs associated with supplying these services from each of the resources that it certifies as eligible to provide each service. Suppliers are provided with the opportunity to recover the costs of any investments undertaken and other fixed costs of providing these services from the first-stage process of offering commitments to provide these services for the coming year or month. CDEC's major role is certifying what units are permitted to provide each service. Consequently, it is important that the penalties a supplier of the ancillary services capacity faces are sufficiently large so that they will make sure that the required amount of certified capacity is available to CDEC during all hours of the time period the supplier is required to provide it. For these reasons, this mechanism provides a strong incentive for least cost investments in the necessary technologies to provide the ancillary services capacity necessary for reliable grid operation.

The penalty for failing to offer ancillary services capacity commitments into the short-term market should at least equal to the replacement cost that the CDEC must pay to obtain this service. In the United States, a financial penalty is often imposed in additional to paying for the replacement cost to ensure compliance by the market participant with its contractual obligations. This approach is used in United States markets when a supplier fails to meet its contractual obligation to provide a service. For example, if supplier fails to provide the required amount of ancillary service capacity to the CDEC, the CDEC would likely to procure capacity from other eligible resources or curtail firm load, each of which has an associated cost. The entity that failed to meet it ancillary services capacity commitment for an hour would be liable for this cost, as well as any additional penalties that CDEC might deem necessary to deter this behavior. Under this penalty scheme, the supplier would have an incentive to ensure that it meets its ancillary services capacity commitments, rather than relying upon the CDEC to find an eligible replacement.

The final component of the proposal is that the cost of supplying these ancillary services be paid by final electricity consumers, rather than having these costs assigned to generation unit owners and requiring them to recover these costs from sales to electricity retailers and final consumers. As discussed in the previous section, final consumers must ultimately pay for all energy and ancillary services costs, and there is a significant market efficiency downside associated with attempting to allocate these costs to generation unit owners, because of the incentives for deviations from least-cost provision of energy and ancillary service created by any cost-allocation process. The most efficient way to recover these costs from retailers and final consumers would be through a per MW peak demand charge and a small per MWh of energy charge assessed on their wholesale energy purchases, consistent with how these charges are incurred. For example, a retailer with a 100 MW annual peak demand would pay a substantial MW-year or MW-month charge and then pay a much smaller per MWh charge based on its hourly withdrawals from the transmission network. This two-part charge would provide strong incentives for retailers to reduce their peak, demand which drives the need for additional ancillary services-capable capacity.

Although customers are prohibited from participating in the CDEC, that should not prevent them from explicitly paying for these ancillary services purchases. At the close of the annual ancillary services auction, the CDEC could compute the total auction revenues that must be collected from consumers to pay for all ancillary services commitments for the coming year. This aspect of the procurement process functions very much like current "node price" determination process, which sets the wholesale price that all regulated retail customers must pay for the coming year. Similar to the node price determination process, the results of these ancillary services commitment auctions could be used to set the \$/MW of peak demand charge for each consumer to recover these costs over the course of the coming year. CDEC could then estimate the total annual hourly payments for ancillary services during the coming year. This would be used to set the \$/MWh charge for ancillary services. The charge would be subject to an annual true-up, where an annual hourly ancillary services payment deficit or surplus would be carried over into the following year. Because the annual hourly payments for ancillary services are likely to be fairly predictable, the annual deficit or surplus is unlikely to impact the \$/MWh charge.

Another important issue with the design of the ancillary service payment mechanism is how to deal with the fact that the supply side of the market is dominated by a few large market participants, particularly when it comes to the resources most likely to be able to provide ancillary services at least cost. The very large share of total AASS produced for a supplier with a dominant position in the ancillary services market implies that it is likely to be able to influence the prices paid for ancillary services commitments in the annual auction. For this reason, it is necessary to add a market power mitigation mechanism to the annual ancillary services commitment auctions. Essentially, this mechanism would require any market participant that is pivotal in the auction for any ancillary service during any day during the commitment period be a price-taker for their pivotal quantity in that auction. The appendix to this document outlines how this market power mitigation mechanism would work under the proposed auction design.

Although the discussion thus far has focused on operating reserves, other products such as black start and voltage support can also be accommodated in this payment mechanism. Suppliers can sell hourly commitments to provide black start and voltage support from facilities qualified to provide these services by the CDEC in the annual commitment auctions. Then during the following year, the suppliers that sold commitments would be required to offer CDEC each hour of the year the amount of certified generation capacity required by the commitments they sold in the annual auction. Suppliers would be subject to penalties that are at least as large at the replacement cost for CDEC to purchase this service during the hour that the supplier fails to meet their commitment plus a penalty to ensure that they find it profitable to meet their commitment rather than rely on CDEC to find a replacement resource.

For the case of out-of-merit generation, all generation units should be required to provide this service if the unit is available that hour, rather than running an annual auction where commitments to provide this service are sold. The main reason for this approach is that system conditions can arise where almost any generation unit in the control area is needed to provide out-of-merit energy. Therefore, CDEC must have the ability to purchase this service from any generation unit in the control area. A generation unit owners that sells out-of-merit energy from a unit with a variable cost that is above the prevailing market price at the unit's location should be paid the variable cost for the unit's output rather than the lower market-clearing price. These payments above the market-clearing price can be recovered from final consumers through a $/MWh charge assessed on their annual consumption, with an annual carryover of the deficit or surplus of revenues recovered from the previous year.

A final issue is the need to allow sellers of retail electricity to set prices to electricity consumers that recover the cost of both wholesale electricity and the ancillary services associated with providing that electricity. The quantity and quality of ancillary services set by CDEC should not be changed without allowing the supplier of the retail electricity the opportunity to recover the increased costs associated with meeting this modified ancillary services requirements. For example, suppose that the level of spinning reserve was set by the CDEC, and generators included the cost procuring this requirement in the retail energy price they offered in supply contracts to electricity consumers. If the CDEC sets a more stringent spinning reserve requirement, the supplier of this retail electricity contract should be able to modify the price that the consumer pays to reflect that higher quality service it is receiving.

## 4. Conclusions

Designing an ancillary services payment mechanism requires balancing the incentives for deviations from least-cost production caused by promising the recovery of regulated costs against the incentives for suppliers to raise prices in excess of economically efficient levels caused by the exercise of unilateral market power by price-setting suppliers. The existing NEC mechanism errs significantly on the side of preventing the exercise of unilateral market power, at the expense of creating substantial incentives for deviations from the least supply of energy and ancillary services. The ancillary services payment proposal outlined in the previous section attempts to introduce stronger incentives for least cost supply of energy and ancillary services, while limiting the opportunities for suppliers of these resources to increase the prices they are paid for providing these services above the levels necessary to recover the costs of providing these services.

## References

[1] National Energy Commission of Chile, letter N°715 September 21th 2010.

[2] U.S. Federal Energy Regulatory Commission (1995) Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Docket RM95-8-000, Washington, DC, March 29.

[3] Technical Norm of Security and Quality of Service, October 2009, National Energy Commission of Chile.

## Appendix

This appendix proposes an auction mechanism for procuring the annual ancillary services commitments and describes the details of implementing the market power mitigation mechanism introduced in Section 3. This auction would be run annually to purchase commitments for the coming year. It could be supplemented with monthly "imbalance" auctions where market participants trade these commitments for the remainder of the year. These monthly auctions would allow CDEC can reduce or increase the ancillary services demands in response to changes in system conditions throughout the operating year.

The first step in the auction involves CDEC defining the hourly requirements for each ancillary service for the coming year. This could be broken down into a weekday demands and weekend demands for different seasons of the year. This would result is 48 hourly demands (24 weekday hours and 24 weekend day hour demands) for the 4 seasons of the year. Let Q(h,d,q,s) equal the demand for ancillary service s in hour h of day d and quarter q, where h=1,2,…,24, d=1,2, q=1,2.3,4, and s=1.2,…,S (where S is the number of ancillary services) For each hour, type of day, and quarter of the year, suppliers of ancillary services are allowed to multi-step offer curves expressing their willingness to supply commitments for each ancillary service for that time period. Suppliers are allowed to submit up to K offer price and quantity pairs for each ancillary service each hour. Setting K equal 3 should allow suppliers sufficient flexibility, without complicating the auction pricing process.

Let q(h,d,q,s,k,m) equal the offer quantity during hour h of day d and quarter q for ancillary service s for offer increment k by market participant m (m=1,2,..,M). Let p(h,d,q,s,k,m) equal the offer price during hour h of day d and quarter q for ancillary service s for offer increment k by market participant m. All market participants would submit the product-level offer curves simultaneously to the auction mechanism. Let x(h,d,q,s,k,m) equal the offer quantity accepted by CDEC in the auction during hour h of day d and quarter q for ancillary service s for offer increment k by market participant m.

CDEC would then determine the values of x(h,d,q,s,k,m) and compute hourly-market clearing prices for each hour of the sample period by choosing the values of x(h,d,q,k,m) to solve the following optimization problem:

$$\min \sum_{q=1}^{4}\sum_{d=1}^{2}\sum_{h=1}^{24}\sum_{s=1}^{S}\sum_{m=1}^{M}\sum_{k=1}^{K} p(h,d,q,s,k,m)x(h,d,q,s,k,m)$$

subject to $0 \leq x(h,d,q,s,k,m) \leq q(h,d,q,s,k,m)$ for all h,d,q,s,k, and m

subject to $\sum_{m=1}^{M}\sum_{k=1}^{K} x(h,d,q,s,k,m) \geq Q(h,d,q,s)$ for all h,d,q, and s.

The shadow price associated with each of product-level hourly supply greater than or equal to hourly demand constraint is the hourly market-clearing price for that ancillary service. All positive values of x(h,d,q,s,k,m) would be paid the market-clearing price for hour h of day d and quarter q for ancillary service s.

Other auction mechanism could be used, but this approach has the advantage of also providing a mechanism for mitigating the market power of large suppliers. Specifically, before the auction is run CDEC will determine the hourly pivotal quantities for each ancillary service for each market participant. The pivotal quantity, qp(h,d,q,s,m), for market participant j for ancillary service s during hour h of day d and quarter q is::

$$qp(h,d,q,s,j) = \max(0,[Q(h,d,q,s) - \sum_{m=1,m=j}^{M} \sum_{k=1}^{K} q(h,d,q,s,k,m)]) \text{ for all h,d,q, and s.}$$

The pivotal quantity is equal to the total hourly demand for ancillary service s that must be supplied by firm j because there are insufficient offers from other suppliers to meet the market demand. All suppliers are required to have offer prices associated with their pivotal quantity reset to zero for all hours and services in order to limit their ability to exercise unilateral market power in the ancillary services commitment auction. This market power mitigation mechanism implies that all suppliers are price-takers in the auction for their hourly pivotal quantity for each ancillary service.

An alternative approach to running the ancillary services commitment auction is a multiple round increasing price auction. The auction process would start with all suppliers setting their pivotal quantity for each ancillary service as their offer quantity at a price of zero. Alternatively, CDEC could specify minimum round 1 zero price hourly quantities for each market participant and each ancillary service. Then in round t (t > 1) of the auction the price for each product would be adjusted upwards by an amount that depends on the amount that the aggregate supply in round t-1 is less that the aggregate demand for that service. Suppliers would then be allowed to offer in incremental amounts of capacity to each hourly ancillary service commitment in round t-1. Suppliers are prohibited from reducing any of their total hourly offer quantities across rounds. The auction for each service terminates at the lowest price at which the aggregate amount supplied is greater than the hourly demand. All of the supply offers at this price are then adjusted downwards by the ratio of the aggregate demand divided by the aggregate supply. Each supplier is then paid the hourly market-clearing price for that service times this adjusted hourly quantity.