

Montevideo, 11 de octubre de 2016.

Señores

Administración del Mercado Eléctrico - ADME

Gerencia Técnica y Despacho Nacional de Cargas

Gerencia Comercial y Administrativa

Att.: Ing. Ruben Chaer / Cra. Marisa León

Ref.: Propuesta de modificación reglamentaria para potencia firme de largo plazo

De nuestra mayor consideración:

Como es de vuestro conocimiento, la reglamentación actual prevé el cálculo de la potencia firme de largo plazo, únicamente para generadores hidroeléctricos y térmicos (Sección XIII, Título III, Capítulos II y III del Reglamento del Mercado Mayorista de Energía Eléctrica, Decreto N° 360/02).

Como fue presentado en anteriores intercambios con ADME, en los últimos años, se han instalado en el sector eléctrico nacional más de 800 MW de generación de fuente eólica, y se prevé más de 1400 MW instalados a fines de 2016. Esta incorporación a la oferta, entendemos contribuye a aumentar la potencia firme de largo plazo del sistema.

En particular, TOGELY COMPANY S.A. tiene instalados actualmente 16,7 MW y se encuentran en proceso de instalación 20 MW. Asimismo, en el sistema se siguen instalando otros parques eólicos, aumentando sustancialmente la penetración de esta fuente de generación en el mercado.

Oportunamente TOGELY COMPANY S.A. presentó un análisis preliminar realizado por Clerk, y donde se solicitaba a ADME analizar el tema y proponer el cambio de la

reglamentación. En respuesta a esta solicitud, ADME responde, en los aspectos sustanciales de su nota del 14 de abril de 2016:

- Su reconocimiento que la metodología de cálculo establecida en la reglamentación debe ser revisada a la luz de la incorporación masiva de energías renovables no convencionales al sistema.
- Que ADME está analizando el tema pero que no puede dar fecha cierta para dar una propuesta de cambio de metodología.
- Que TOGELY COMPANY S.A en calidad de Participante puede presentar ante ADME una propuesta de cambio al Reglamento, cumpliendo con los requisitos establecidos en el Artículo 14 del Título VI, Sección I del Decreto 360/002; y este será tramitado por ADME según lo establecido en el Artículo 15 del mismo título y sección.

De acuerdo con el planteo realizado por ADME, por este medio realizamos una propuesta de cambio de Reglamento, en los términos del informe técnico adjunto realizado por Clerk y que hacemos nuestro.

Esta propuesta cumple con los extremos Reglamentarios solicitados y en particular:

- Con el artículo 12 Título VI Sección I del Decreto 360/002, que establece en su literal a) como uno de los fundamentos para proponer un cambio a la Reglamentación “la existencia de vacío regulatorio ante cambios en el sistema o condiciones en su operación, que no fueron previstos y que afectan la economía, calidad o seguridad del sistema, o la competitividad y eficiencia del MME, o la seguridad del suministro”. Entendemos que la existencia de este vacío está reconocido por todos los actores y autoridades del sistema.
- Con el artículo 14 Título VI Sección I del Decreto 360/002. En especial la propuesta cumple con lo solicitado en los literales:
 - a) Explica las razones por las que se considera que la propuesta constituye un aporte para mejorar la regulación vigente.
 - b) Describe los antecedentes, el alcance y los fundamentos de la propuesta e identifica los artículos del Reglamento o de los Anexos que propone cambiar.
 - c) Incluye nombre, domicilio y representación si corresponde, cuando la propuesta proviene de un Agente o Participante del Mercado. TOGELY COMPANY S.A. lo hace a través de esta nota que está presentando.

Por lo expuesto, entendemos que a partir de esta presentación la presente solicitud será tramitada por ADME en los términos establecidos en el Artículo 15 del Título VI de la sección I del Decreto 360/002, tal y como la propia ADME indicó en su nota ya referida.

TOGELY COMPANY S.A. está domiciliada en Luis Piera 1921 Piso 10 y está representada por Francis Raquet en su carácter de Vicepresidente.

Quedamos a disposición, nosotros y nuestros consultores, para aportar la información que pudiera ayudar a una solución rápida a este vacío normativo que tiene, a nuestro juicio, un impacto relevante en el funcionamiento del mercado

Sin otro particular, lo saludamos muy atentamente,

A handwritten signature in dark ink, appearing to read 'Francis Raquet', with a large, sweeping flourish extending from the end of the name.

Francis Raquet

TOGELY COMPANY S.A.

Clärk® ingeniería para
la nueva energía

**Solicitud para incorporar a la reglamentación el
reconocimiento de Potencia Firme a las Energías Renovables
No Convencionales**

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1.- Antecedentes

El problema planteado es la ausencia dentro de la reglamentación del Mercado Eléctrico del reconocimiento del aporte de potencia y energía firmes que realizan al sistema las Energías Renovables No Convencionales (ERNC), en particular la energía eólica y la solar fotovoltaica, que han tenido un importante desarrollo en el país.

El Reglamento del Mercado Mayorista de Energía Eléctrica (RMME), en su Sección XIII define los conceptos de potencia firme y garantía de suministro.

En un esquema regulatorio como el uruguayo, el aseguramiento del cubrimiento de los requerimientos de energía de los Participantes Consumidores, se basa en el aporte anticipado de los mismos a la garantía de suministro, a partir del compromiso de potencia firme de largo plazo. La potencia firme de largo plazo tiene por objeto asegurar el cubrimiento anticipado de la garantía de suministro.

Este requerimiento, se mide en el denominado Período Firme, definido por las horas fuera del bloque de valle.

De acuerdo al Artículo 219 del RMME, un Participante Productor puede vender por contratos y en el Servicio de Reserva Nacional hasta su potencia firme de largo plazo comercializable.

El procedimiento de cálculo de la potencia firme de largo plazo, se establece en el Título III de la Sección XIII del RMM, pero solo refiere a la generación de tipo hidroeléctrica y térmica, no considerando otras tecnologías, como la generación de fuente eólica o solar. En cualquier caso, es el DNC quien debe calcular en forma mensual la potencia firme de largo plazo e informar los valores a los participantes del mercado.

Es importante destacar que nuestra reglamentación, al reconocer la energía firme de las centrales hidroeléctricas, acepta el aporte de fuentes de alta variabilidad sujeta a condiciones climáticas.

El vacío regulatorio respecto de las ERNC genera un conjunto de problemas y disfuncionalidades del sistema y el mercado que es necesario corregir. Entre otros es posible mencionar:

- El no reconocimiento del aporte que hacen las ERNC a la seguridad de suministro del sistema puede llevar en el futuro a tomar decisiones erróneas respecto a las necesidades de expansión del sistema y el tipo de tecnología adecuada para cubrir déficits de potencia y energía. En

particular puede llevar a un sobredimensionamiento del parque de generación con la consecuente desoptimización del sistema y su consiguiente impacto de mediano plazo sobre los consumidores.

- Genera una discriminación entre productores en función de la tecnología que utilizan para generar. Esto, en el mediano plazo, puede generar un sesgo a favor de la incorporación de algunas tecnologías, en especial de origen térmico. Incluso podría llegarse al absurdo de que a los efectos de cumplir el requerimiento de contratos de comercialización, se incorporen generadores térmicos no necesarios para el sistema.

En las siguientes páginas, y a modo de antecedentes de nuestra propuesta, se presentan distintas alternativas metodológicas basadas en reglas existentes en otros mercados eléctricos relevantes para el cálculo de la potencia firme de largo plazo de las energías renovables no convencionales; opiniones técnicas relevantes, así como la extensión de los principios conceptuales del propio RMMEE que se utilizan para el caso de la generación hidroeléctrica.

Resulta necesario destacar que las reglas de otros mercados no constituyen una mera referencia metodológica, sino que en el largo plazo los mercados compiten, también con sus reglas, por las inversiones.

1.1 Valor constante de capacidad

En algunos mercados como en los estados de Washington, Colorado, Idaho, Montana, Utah y Wyoming, se utilizan métodos que establecen un valor constante de capacidad, según algún criterio.

Por ejemplo, el Rocky Mountain Area Transmission, que atiende parcialmente a los estados de Colorado, Idaho, Montana, Utah y Wyoming, utiliza un valor de capacidad de la energía eólica con fines de planificación del 20 % de la capacidad instalada.

También Puget Sound Energy, que es una empresa de generación y transmisión del estado de Washington, utiliza un 20 % de la capacidad de placa del parque generador o el equivalente a $2/3$ del factor de capacidad del mes de enero, que es el mes donde en el área de servicio de la compañía se registra el pico de demanda. En los cálculos que se presentan, según este método para el caso de Uruguay, se toma el equivalente a $2/3$ del factor de capacidad del mes de julio (que representa el mes del pico tradicional de la demanda, si bien en los últimos tiempos la tendencia es a valores similares en el verano).

1.2 Método analítico (Fórmula de Voorspools y D'haeseleer)

Voorspools y D'haeseleer determinaron fórmulas analíticas para el cálculo del crédito de capacidad de la potencia eólica, tal como se reporta en el trabajo de Sergio Botero B. et al.

Para sistemas con penetración de generación eólica mayor al 1 %, como es el caso de Uruguay, el crédito de capacidad (CC) se calcula como:

$$CC = \alpha \frac{CF_w}{R_s} (1 + \beta e^{-b(x-1)})$$

Donde:

CC es el crédito por capacidad como un porcentaje de la potencia eólica instalada.

CFw es el factor de capacidad de proyectos eólicos similares o calculado.

$$\alpha = 37,6$$

$$\beta = 1,843$$

$$b = 0,094$$

x es el nivel de penetración de energía eólica en el sistema en p.u.

R_s es la confiabilidad del sistema incluyendo las plantas convencionales.

1.3 Método adaptado RMME (Análogo generación hidroeléctrica)

En el Artículo 222 del RMME, se establece la metodología de cálculo para la potencia firme de largo plazo de una central hidroeléctrica.

El método calcula la potencia firme de largo plazo mensual como la energía firme hidroeléctrica mensual dividido el número de horas del período firme de dicho mes.

Para ello el DNC calcula la energía firme hidroeléctrica mensual del MME con el modelo de largo plazo con la serie histórica de caudales y la base de datos acordada para la Programación Estacional de largo plazo. Se simulan varios años consecutivos para obtener resultados independientes del estado inicial de los embalses, y se toman los resultados de generación para el tercer año.

Como resultado se obtiene la serie de generación hidroeléctrica mensual total del país, y para cada mes, se considera la energía firme hidroeléctrica mensual del MME la que resulta de la serie de generación hidroeléctrica del MME durante el período firme para una probabilidad de excedencia del 95% (noventa

y cinco por ciento). Luego el DNC determina la energía firme hidroeléctrica mensual para cada central, las cuales sumadas, deben igualar (dentro de un margen de tolerancia) a la energía firme hidroeléctrica mensual del MMEE.

El cálculo de la energía firme de largo plazo eólica puede realizarse según un procedimiento similar, pero en este caso no es necesaria la realización de simulaciones de varios años, considerando las series históricas, como en el caso de la energía hidroeléctrica, ya que con un año de datos de producción del parque eólico, la información estadística es suficiente para estimar la energía que el parque podrá suministrar en el largo plazo y con el valor de probabilidad que se desee. Siguiendo el método del Artículo 222, se propone utilizar una probabilidad de excedencia del 95 %.

Por otra parte, los datos de producción diezminutales disponibles del parque eólico, pueden ser agrupados en ventanas de tiempo de diferentes dimensiones, a los efectos del cálculo de la energía firme: diarios, semanales, mensuales.

Considerando las características del sistema uruguayo, con una fuerte presencia de generación hidroeléctrica, las características de los embalses y la forma de operación del sistema, se entiende que de usarse este método, el paso apropiado de tiempo para el cálculo de la energía firme eólica debería ser semanal.

Con los datos semanales de energía, y dividiéndolos entre el tiempo del período firme, se obtienen los valores de potencia media semanal/mensual, de los cuales se toma el valor con probabilidad de excedencia del 95 % para determinar la potencia firme del largo plazo.

1.4 *Paper* presentado por ADME en el Seminario hacia una Matriz Energética Sostenible.

El equipo técnico de ADME presentó, el pasado 26 de abril de 2016 en Buenos Aires, en el Seminario Transición hacia una Matriz Energética Sostenible, organizado por el Instituto Argentino de la Energía "General Mosconi" un trabajo que referido al ingreso de la energía eólica, la gestión de los embalses y la potencia firme del sistema.¹

¹ INCIDENCIA DEL INGRESO DE EOLICA EN LA EVOLUCION DE LA COTA DE BONETE Y POTENCIA FIRME DEL SISTEMA ELECTRICO URUGUAYO. Autores: Ing. María Cristina Álvarez, Ing. Gabriela Batista, Ing. Ruben Chaer. ADME, Administración del Mercado Eléctrico, Montevideo, Uruguay

Al los efectos de esta presentación, resulta importante transcribir a continuación, el punto de las Conclusiones, “6.1 Potencia firme de la generación hidráulica y de fuentes renovables no convencionales”

“El informe de Garantía de Suministro 2016 que elaboró ADME muestra, tal como se ve en el Gráfico 5, que la Potencia Firme reconocida al sistema hidráulico decrece con la incorporación de la generación de fuentes renovables no convencionales. Para aclarar las curvas mostradas: se grafica la potencia firme de la generación hidráulica calculada según los criterios del Decreto 360 del año 2002, para estos tres casos: con la incorporación de ERNC prevista en los planes de expansión del país, sin dichas incorporaciones futuras, siendo sustituidos por falla y, en el tercer caso, asignando a la generación de ERNC una potencia firme calculada con los mismos criterios que para la hidráulica.

La causa de esta degradación de la potencia firme hidráulica se explica por la metodología definida en la normativa vigente del sistema uruguayo (Art. 222 del Decreto 360/002) para el cálculo de la misma. Se evalúa con la energía hidráulica generada en las horas del llamado “período firme” (exceptuando el valle) calculada mediante simulaciones con el modelo de largo plazo con una probabilidad de excedencia del 95%. El ingreso de generación eólica al sistema desplaza generación hidroeléctrica en horas del “período firme” y esto hace decrecer la potencia firme de generación hidroeléctrica.

Por otro lado, la normativa actual no define la potencia firme de generación de origen eólica o solar, por lo que para todos los estudios de planificación y programación del sistema, ambas se consideran nulas.

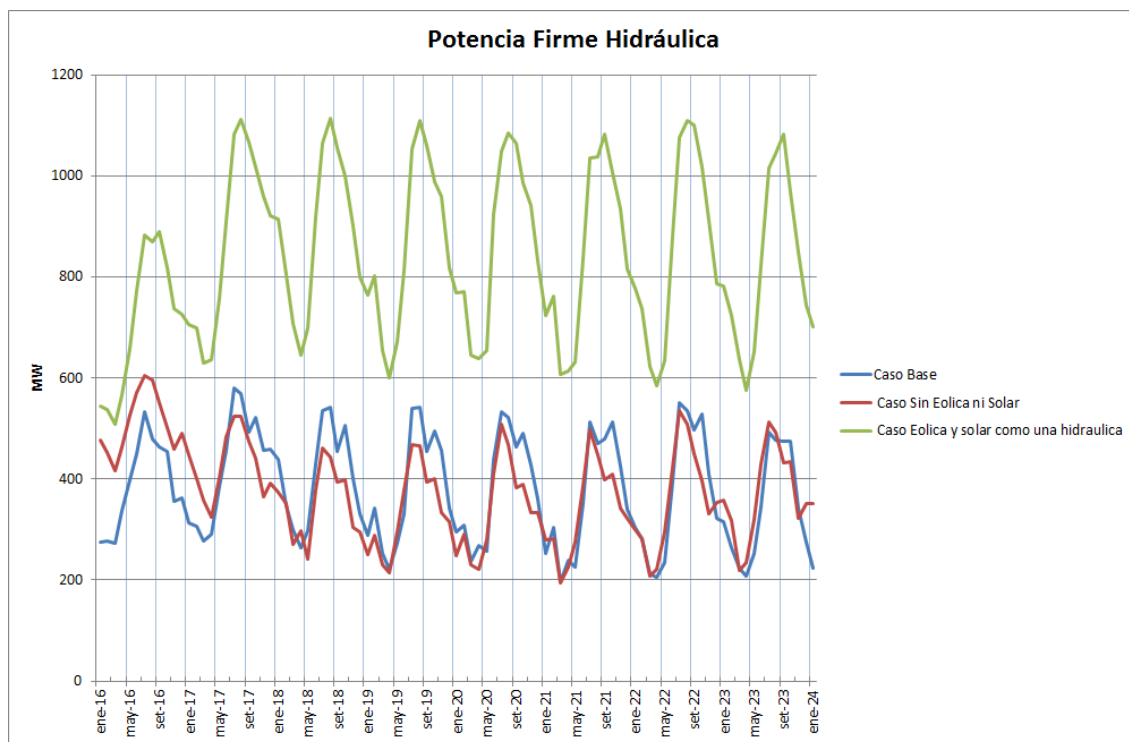


Gráfico 5: Potencia firme hidráulica. Fuente: Informe de Garantía de Suministro, ADME

Sin embargo, tal como viene ocurriendo en muchos sistemas eléctricos con ingreso de energías renovables no convencionales, se hace necesario definir la potencia firme de ese tipo de generación y redefinir el criterio de cálculo de la potencia firme de generación hidroeléctrica.

Esto permitirá una planificación de la expansión del sistema eléctrico más adecuada teniendo en cuenta los criterios de seguridad de suministro y de economía que correspondan y, además, facilitará la posibilidad de incluir en los contratos bilaterales la potencia firme como un producto a comercializar.

Los análisis hechos para el sistema eléctrico uruguayo simplificado, para ingreso de 20 y 1400 MW de eólica, muestran una importante disminución del valor esperado de energía no suministrada (llamada “falta”) en el bloque horario de mayor demanda (poste 1) para el caso de ingreso 1400 MW de eólica. Esto se ve claramente en el Gráfico 6, donde se graficaron las potencias de “falta” para distintas probabilidades de excedencia así como también promedio en ambos casos.

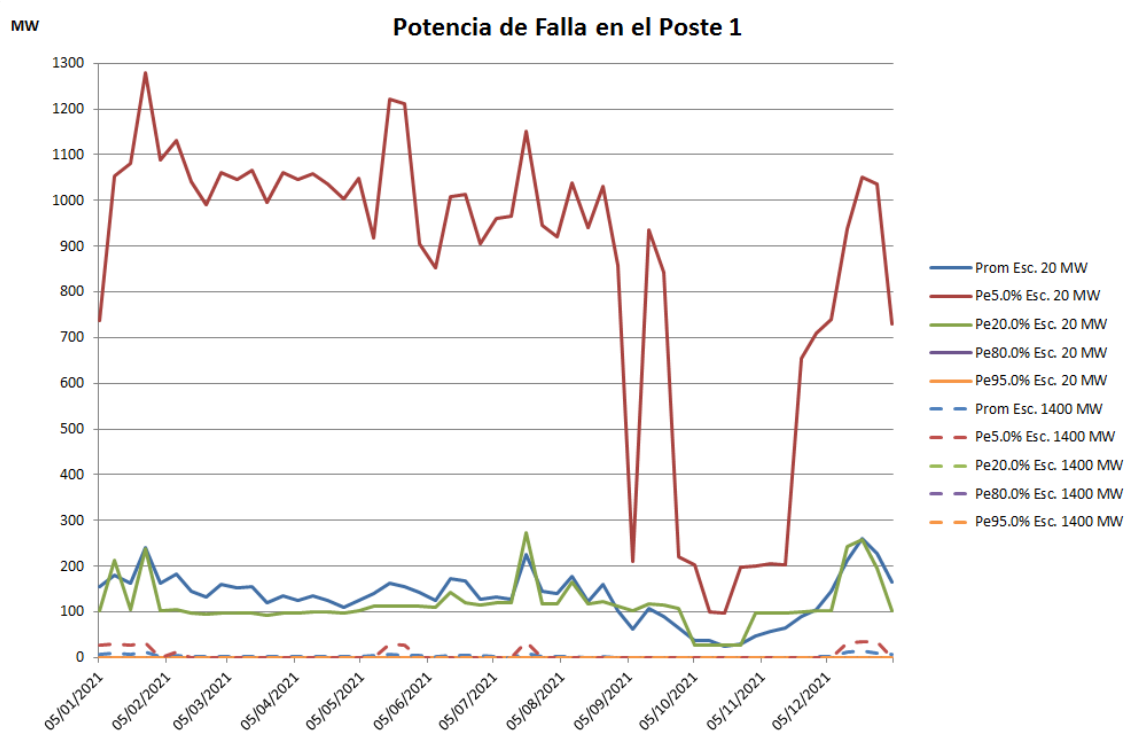


Gráfico 6: Potencia de Falla en el Poste 1 para los dos escenarios estudiados con distintas probabilidades de excedencia.

Los valores anuales promedio de energía no suministrada en horas de mayor demanda, lo que representaría un faltante de potencia para dar la misma en horarios de punta, son de 133 MW para el caso de ingreso de 20 MW de eólica, y de 3 MW para el caso de 1400 MW de eólica. Esto reafirma lo dicho

en el punto 5), respecto a que es importante analizar la firmeza que la eólica, en conjunto con la hidráulica, aportan a la disponibilidad de potencia del sistema, ya que la primera permite almacenar energía en los embalses al sustituir el despacho hidráulico cuando hay viento.”

1.5 Informe COWI – Integration of large amounts of wind energy in Uruguay

El informe realizado por la consultora COWI para el Banco Interamericano de Desarrollo y la Dirección de Energía, además de reconocer la importancia del reconocimiento del aporte de la energía eólica a la potencia firme y seguridad del sistema, propone un método basado en cuanta energía térmica es capaz de desplazar la energía eólica que se incorpora al sistema.

En efecto la energía térmica es la que tiene los mayores niveles esperado de respuesta en cualquier condición del sistema; y por tanto si la energía eólica es capaz de desplazar la incorporación de potencia de energía, manteniendo los niveles de falla de diseño del sistema, este desplazamiento de potencia debería otorgarse a la energía eólica.

Se adjunta en anexo el informe completo de la consultora.

2.- Metodologías alternativas

De acuerdo a los análisis realizados, y al estudio de alternativas regulatorias utilizadas en otros mercados, entendemos que para el caso uruguayo hay dos alternativas que resultan más adaptadas a la realidad de nuestro mercado y a las características físicas de nuestro sistema interconectado.

La primera es la que utiliza como base la actual regla regulatoria utilizada para la energía hidroeléctrica, teniendo en cuenta además la sinergia entre las tecnologías (especialmente la complementariedad de la energía eólica y la capacidad de almacenamiento de las centrales hidroeléctricas).

La segunda es una metodología, que toma como base la propuesta de la consultora COWI, realizándose una adaptación para las características del sistema uruguayo y especialmente para realizar un reconocimiento adecuado del aporte de la generación hidroeléctrica a la firmeza del sistema. El método, como fue mencionado, implica determinar qué cantidad de potencia térmica es capaz de sustituir cada una de las tecnologías renovables.

2.1 Método adaptado RMME (Análogo generación hidroeléctrica)

Inicialmente, se determina la Potencia Firme de las Centrales Hidroeléctricas (H) con el método actual establecido en el Art. 222 del RMME, pero considerando nula la potencia instalada de las ERNC, y sustituyendo para los cálculos las máquinas ERNC por generadores térmicos..

Esta potencia se define como la Potencia Firme Base Hidroeléctrica. (**PFBH**)

Luego, se determina la Potencia Firme del conjunto Hidroeléctrico y ERNC, con la metodología del RMME, utilizando una probabilidad de excedencia del 95 %. Esto se realiza con el parque utilizado en el Informe de Garantía de Suministro de ADME. Esta potencia se define como la Potencia Firme Renovable Total del Sistema. (**PFRTS**).

En la misma simulación y para la probabilidad de excedencia definida, se calculan los aportes de cada tecnología (hidráulica, eólica, fotovoltaica) a la PFRTS. A partir de los mismos, se determinan los porcentajes de aporte de cada tecnología al PFRTS, dividiendo el aporte de cada tecnología sobre la PFRTS. . Resultan así: el porcentaje Eólico (**%E**), el porcentaje Fotovoltaico (**%F**) y el de las Centrales Hidroeléctricas (**%H**).

La Potencia Firme Final Eólica (PFFE) se calcula como:

$$\text{PFFE} = (\text{PFRTS} - \text{PFBH}) \times (\% E)$$

La Potencia Firme Final Fotovoltaica (PFFF) se calcula como:

$$\text{PFFF} = (\text{PFRTS} - \text{PFBH}) \times (\% F)$$

Para el cálculo de la Potencia Firme Final Hidroeléctrica (PFFH) se procede de la siguiente manera:

Se determina un valor de reconocimiento del aporte del complejo hidroeléctrico al filtrado de la variabilidad de las ERNC, que está dado por su capacidad de almacenaje y de proveer potencia rotante al sistema, esto es, la Capacidad de Filtrado de Centrales Hidroeléctricas (**CFH**):

$$\text{CFH} = (\text{PFRTS} - \text{PFBH}) \times (\% H)$$

La Potencia Firme Final Hidroeléctrica se calcula como:

$$\text{PFFH} = \text{PFBH} + \text{CFH}$$

Tal como surge de la construcción de las variables anteriores, se puede verificar que la suma de las Potencias Firmes Finales de todas las tecnologías resulta:

$$\text{PFFE} + \text{PFFF} + \text{PFFH} =$$

$$=(\text{PFRTS} - \text{PFBH}) \times (\% E) + (\text{PFRTS} - \text{PFBH}) \times (\% F) + \text{PFBH} + (\text{PFRTS} - \text{PFBH}) \times (\% H) =$$

$$=\text{PFRTS}$$

Es decir la Potencia Firme Renovable Total del Sistema.

La metodología propuesta tiene la propiedad de reconocer la capacidad de filtrado de la generación hidroeléctrica.

Se observa que la utilización de esta adaptación del método actual vigente del RMMEE, no significa una disminución de la potencia firme hidroeléctrica cuando se incorporan ERNC al sistema.

Luego de determinada la potencia firme de cada tecnología, se define un valor para cada máquina, prorrateando por la potencia de placa o por la potencia autorizada en el Convenio de Uso.

Asimismo, luego se podría ajustar el aporte de cada máquina por la disponibilidad promedio del último año.

2.2 Método de la Potencia Térmica Equivalente

La base conceptual es definir la Potencia Firme, tanto del total de energías renovables como de cada una de las tecnologías involucradas, en función de cuánta Potencia Firme térmica es capaz de desplazar (no necesaria).

El método asume que en cuanto a firmeza, la Potencia Térmica sería la más valiosa en la suma Disponibilidad más Capacidad de Gestión, y por tanto el resto de las tecnologías aportan en función de cuanto pueden desplazar de esta.

Los cálculos deben hacerse en todos los casos para alcanzar un nivel de confiabilidad dado (i.e. la falla no puede superar un determinado valor a definir). Por ejemplo, que el volumen de energía racionada con probabilidad 5% de ser excedido no supere al 2% de la demanda anual.

El método implica hacer simulaciones sustituyendo (con y sin), según el caso, las ERNC por Térmica, de modo de mantener el mismo nivel de confiabilidad del sistema.

A continuación, se desarrolla el procedimiento:

a.- Se determina el Plan de Expansión de la oferta y la demanda esperada, con sus distintas tecnologías de acuerdo a la Programación Estacional vigente inmediatamente anterior a fijar los cálculos de Potencia Firme de los generadores (Año n).

b.- Se utiliza el nivel de falla aceptable definido por la Dirección Nacional de Energía para las simulaciones de largo plazo.

c.- Se realizan simulaciones del sistema considerando solo la existencia de máquinas térmicas, considerando la disponibilidad histórica (promedio del último año de las turbinas a gas que tienen la entrada en servicio más cercana a la fecha de análisis). El valor resultante de MW térmicos necesarios para el

año (n+2), para ajustar al nivel de confiabilidad establecido es **Potencia Térmica Individual Total (PTIT)**.

d.- Luego se modela el sistema incorporando como única tecnología renovable la hidráulica, con la cantidad de MW existentes. Con esta oferta se calcula la potencia térmica necesaria para abastecer la demanda en las condiciones fijadas también para el año n +2, con una probabilidad de excedencia del 50 %. La diferencia entre la PTIT y este valor obtenido determina la **Potencia Firme Hidráulica Individual (PFHI)**.

e.- Del mismo modo, se modela el sistema como si la única energía renovable fuera la energía eólica (en las cantidades establecidas en la oferta planificada). Se determina cuánto de la PTIT desplaza en el año n + 2, tomando para la fuente eólica P50. Este valor será la **PFEI (Potencia Firme Eólica Individual)**.

f.- Se calcula de la misma manera la **PFFI (Potencia Firme Fotovoltaica Individual)**.

g.- Se define la suma de Potencias Firmes Individuales como:

$$SPFI = PFHI + PFEI + PFFI$$

g.- Luego se realiza el mismo cálculo para el conjunto de las energías renovables de manera conjunta (hidro +eólica + fotovoltaica) y así se obtiene la **PFC (Potencia Firme Conjunta)**.

h.- Dado que la PFC es mayor que la suma SPFI, hay que repartir la diferencia entre las distintas tecnologías. La diferencia entre la PFC y las potencias individuales es atribuible a la sinergia entre las tecnologías y especialmente al rol del almacenamiento hidráulico; y su capacidad de tener potencia rotante.

i.- Este reparto se hace de manera proporcional a las potencias firmes individuales.

j.- Para cada tecnología se suma la potencia individual a la cuota parte del aumento conjunto. Así se determina la Potencia Final de Cada Tecnología:

$$PFFH = PFHI + PFHI \times (PFC - SPFI) / SPFI \quad (\text{Potencia Firme Final Hidráulica})$$

$$PFFE = PFEI + PFEI \times (PFC - SPFI) / SPFI \quad (\text{Potencia Firme Final Eólica})$$

$$PFFF = PFFI + PFFI \times (PFC-SPFI)/SPFI \quad (\text{Potencia Firme Final Fotovoltaica})$$

Luego de determinada la potencia firme de cada tecnología, se define un valor para cada máquina, prorrateando por la potencia de placa o por la potencia autorizada en el Convenio de Uso.

Asimismo, luego se podría ajustar el aporte de cada máquina por la disponibilidad promedio del último año.

Luego se puede adicionar a las renovables el aporte de otros almacenamientos o tecnologías que disminuyan la cantidad de térmica necesaria en el sistema. De esta manera se pueden ir ajustando las reglas con el desarrollo físico del sistema.

El ajuste de los valores calculados se realizará anualmente, antes de finalizar el año correspondiente.

Esto permite mantener adecuados niveles de estabilidad de las reglas con los ajustes que adapten las normas a la realidad del mercado.

3.- Metodología propuesta

Entendemos que dado los cambios que ha experimentado nuestro sistema eléctrico, y la necesidad de determinar para el futuro mecanismos de medición de la potencia del sistema que resulten adaptados a la matriz de oferta, clara y transparente; es necesario cambiar la metodología actual.

El cambio de la estructura del sistema uruguayo ha sido de gran magnitud, no solo por la incorporación de potencia al sistema, sino en las características de la misma. Hemos pasado de un sistema con elevados déficit de energía y riesgos de falla; a uno con importantes cantidades de excedentes.

Asimismo, la generación incorporada está sujeta a la aleatoriedad de su fuente, al igual que la generación hidráulica, de larga presencia en el sistema. Esto genera nuevas necesidades regulatorias respecto de reconocer el aporte de todas las tecnologías, valorar las sinergias entre ellas, dar valor a la capacidad de almacenamiento; y generar reglas que lleven a decisiones empresariales alineadas con un parque óptimo.

La nueva metodología debe, a nuestro juicio, cumplir con algunos principios generales. Entre otros:

- La solución adoptada debe ser equitativa para todas las tecnologías de generación. No puede haber sesgo para una tecnología en particular.
- La solución debe permitir que se tienda hacia el óptimo del sistema. No deben existir incentivos para incorporar ni más ni menos potencia que la requerida, ni tener sesgo para una tecnología en particular.
- La solución que se adopte para el conjunto del sistema: Reserva Nacional etc., debe ser congruente luego con las exigencias del requerimiento de potencia que se exijan a los contratos entre particulares.
- La solución debe tener estabilidad en el tiempo y un mecanismo claro y transparente de actualización.

La metodología que, a nuestro juicio mejor se adapta tanto a las nuevas características de sistema y al mismo tiempo cumple con los principios enunciados es la definida en el punto **2.2 Método de la Potencia Térmica Equivalente**.

Asimismo, el método propuesto, es completamente adaptable a cambios en el sistema por incorporación de nuevas tecnologías, especialmente de sistemas de almacenamiento (centrales de bombeo, baterías, etc.).

Finalmente, entendemos como un valor adicional la simplicidad conceptual de la propuesta. En suma, la potencia o energía firmes tienen valor en la medida que aporta un determinado nivel de confiabilidad al sistema (un nivel de falla esperada que no supere determinado umbral); cualquier tecnología que aporte igual valor a ese nivel de confiabilidad tiene que tener el mismo nivel de potencia reconocida.

Por tanto, a continuación se detalla el articulado propuesto para la modificación reglamentaria.

4.- Propuesta de Normativa

A los efectos de reglamentar la metodología propuesta se proponen los siguientes cambios en la Sección XIII del Decreto N° 360/02.

Se sustituye el Título III, Potencia Firme de Largo Plazo y Energía Firme, por la siguiente redacción:

TITULO III. POTENCIA FIRME DE LARGO PLAZO Y ENERGIA FIRME

CAPITULO I. CARACTERISTICAS GENERALES

Artículo 220. La Potencia Firme de Largo Plazo y la de Corto Plazo se calculan mensualmente.

La Potencia Firme Comercializable de un Participante Productor es el resultado de:

- a) la suma de la Potencia Firme de la generación propia o, en el caso de un Comercializador, la potencia que comercializa por Acuerdos de Comercialización de Generación;
- b) más la potencia que compra por Contratos de Respaldo. Para el cálculo de la Potencia Firme de Largo Plazo sólo se considerarán los Contratos de Respaldo cuyo objeto es afirmar la potencia instalada en centrales hidroeléctricas.

Por lo tanto, la Potencia Firme de Largo Plazo comercializable de un Participante Productor no podrá superar la potencia instalada propia o, en el

caso de un Comercializador, la potencia instalada de las centrales que comercializa por Acuerdos de Comercialización de Generación.

Artículo 221. El DNC debe calcular la Potencia Firme de Largo Plazo y de Corto Plazo para cada central hidroeléctrica, [eólica](#), [solar](#) y cada unidad generadora térmica (o Grupo a Despachar en caso de agrupamiento de unidades para el despacho) de los Participantes Productores, incluyendo las comprometidas en contratos de exportación.

La potencia comprometida en un contrato de importación se considerará Potencia Firme de Largo Plazo.

Antes de finalizar cada año, la ADME pondrá en conocimiento de todos los Participantes la Potencia Firme de cada unidad generadora térmica del MMEE (o Grupo a Despachar en caso de agrupamiento de unidades para el despacho), cada contrato de importación y cada central hidroeléctrica, [eólica y solar](#) del MMEE, y el total que comercializa cada Participante Productor.

CAPITULO II. POTENCIA FIRME DE GENERACION TERMICA

Artículo 222. El DNC calculará la Potencia Firme de Largo Plazo de cada unidad térmica (o de un Grupo a Despachar térmico, en caso de agrupamiento de unidades para el despacho) como su potencia efectiva afectada por la Disponibilidad Comprometida para Garantía de Suministro.

Previo al inicio de cada año y junto con la coordinación del Programa Anual de Mantenimiento, cada Participante Productor informará a la ADME la Disponibilidad Comprometida para Garantía de Suministro para cada mes del siguiente año y que como promedio anual no podrá superar una disponibilidad máxima de referencia definida en el 95% (noventa y cinco por ciento) ni la disponibilidad verificada histórica promedio de los últimos doce meses.

La potencia máxima contratable mensual de cada unidad térmica coincidirá con su Potencia Firme de Largo Plazo.

Artículo 223. Para cada unidad o Grupo a Despachar térmico, el DNC deberá realizar el seguimiento mensual y anual de su indisponibilidad y calcular su Potencia Firme de Corto Plazo.

Se considerará que en un mes un Participante Productor tiene un incumplimiento a sus compromisos de Potencia Firme por Garantía de Suministro si se registra en dicho mes, por lo menos una de las siguientes condiciones:

- a) Durante el mes fue necesario programar racionamientos por déficit de generación y durante uno o más días con racionamiento, el Participante resultó con una disponibilidad menor que la Potencia Firme total que

vende en contratos y al Servicio de Reserva Nacional, exceptuando de este cálculo la indisponibilidad por Programa Anual de Mantenimiento coordinado por el DNC.

- b) En el mes, su Potencia Firme de Corto Plazo mensual comercializable fue menor que el total vendido en dicho mes por Contratos más el Servicio de Reserva Nacional.

Antes del 15 de octubre de cada año, el DNC deberá verificar el cumplimiento de los compromisos de Potencia Firme por Garantía de Suministro de cada Participante Productor en los últimos doce meses.

Ante incumplimientos reiterados de un Participante Productor a su Potencia Firme por Garantía de Suministro, salvo contingencias o condiciones extraordinarias debidamente justificadas o fuerza mayor, el DNC deberá reducir la Disponibilidad Comprometida para Garantía de Suministro a la disponibilidad verificada histórica promedio en los últimos doce meses, recalculando su Potencia Firme de Largo Plazo e informar al Participante.

Si como consecuencia de la reducción en su Potencia Firme de Largo Plazo, un Participante Productor resulta con menos Potencia Firme de Largo Plazo que la que ya tiene comprometida en venta por contratos y Servicio de Reserva Nacional, deberá antes de finalizar el año, comprar por Contratos de Respaldo la Potencia Firme de Largo Plazo faltante.

Antes de la finalización de cada año, el DNC deberá verificar para cada Participante Productor si dispone de suficiente Potencia Firme de Largo Plazo comercializable para cubrir sus compromisos de ventas de Potencia Firme por contratos y Servicio de Reserva Nacional. De resultar con faltantes en uno o más meses, se le asignará como un requerimiento de Reserva Anual a licitar para dichos meses.

Artículo **224**. Para cada mes, la energía firme de una generación térmica se calculará multiplicando su Potencia Firme de Largo Plazo del mes por el número de horas del Período Firme en dicho mes.

CAPITULO III. POTENCIA FIRME DE GENERACION HIDROELECTRICA, EÓLICA Y FOTOVOLTAICA

Artículo 225. Para el cálculo de la Potencia Firme de la generación hidroeléctrica, eólica y fotovoltaica, se utilizará el siguiente procedimiento:

- a. Se determina el Plan de Expansión de la oferta y la demanda esperada, con sus distintas tecnologías de acuerdo a la Programación Estacional vigente inmediatamente anterior a fijar los cálculos de Potencia Firme de los generadores (Año n).

- b. Se utiliza el nivel de falla aceptable definido por la Dirección Nacional de Energía para las simulaciones de largo plazo. Como criterio inicial se considerará que el volumen de energía racionada con probabilidad 5% de ser excedido no supere el 2% de la demanda anual.
- c. Se realizan simulaciones del sistema considerando solo la existencia de máquinas térmicas, considerando la disponibilidad histórica (promedio del último año de las turbinas a gas que tienen la entrada en servicio más cercana a la fecha de análisis). El valor resultante de MW térmicos necesarios para el año (n+2), para ajustar al nivel de confiabilidad establecido, es la Potencia Térmica Individual Total (PTIT).
- d. Luego se modela el sistema incorporando como única tecnología renovable la hidráulica, con la cantidad de MW existentes. Con esta oferta se calcula la potencia térmica necesaria para abastecer la demanda en las condiciones fijadas también para el año n +2, con una probabilidad de excedencia del 50 %. La diferencia entre la PTIT y este valor obtenido determina la Potencia Firme Hidráulica Individual (PFHI).
- e. Del mismo modo, se modela el sistema como si la única energía renovable fuera la energía eólica (en las cantidades establecidas en la oferta planificada). Se determina cuánto de la PTIT desplaza en el año n + 2, tomando para la fuente eólica P50. Este valor será la PFEI (Potencia Firme Eólica Individual).
- f. Se calcula de la misma manera la PFFI (Potencia Firme Fotovoltaica Individual).
- g. Se define la suma de Potencias Firmes Individuales como:
$$SPFI = PFHI + PFEI + PFFI$$
- h. Se realiza el mismo cálculo para el conjunto de las energías renovables de manera conjunta (hidro +eólica + fotovoltaica) y así se obtiene la PFC (Potencia Firme Conjunta).
- i. Dado que la PFC es mayor que la suma SPFI, se reparte la diferencia entre las distintas tecnologías. La diferencia entre la PFC y las potencias individuales es atribuible a la sinergia entre las tecnologías y especialmente al rol del almacenamiento hidráulico; y su capacidad de tener potencia rotante. Este reparto se hace de manera proporcional a las potencias firmes individuales.
- j. Para cada tecnología se suma la potencia individual a la cuota parte del aumento conjunto. Así se determina la Potencia Final de Cada Tecnología:

$$PFFH = PFHI + PFHI \times (PFC - SPFI) / SPFI \quad (\text{Potencia Firme Final Hidráulica})$$

$$PFFE = PFEI + PFEI \times (PFC-SPFI)/SPFI \text{ (Potencia Firme Final Eólica)}$$

$$PFFF = PFFI + PFFI \times (PFC-SPFI)/SPFI \text{ (Potencia Firme Final Fotovoltaica)}$$

Luego de determinada la potencia firme de cada tecnología, se define un valor para cada máquina, prorrateando por la potencia de placa.

Antes del 15 de octubre de cada año, el DNC deberá verificar el cumplimiento de los compromisos de Potencia Firme por Garantía de Suministro de cada Participante Productor en los últimos doce meses.

Ante incumplimientos reiterados de un Participante Productor a su Potencia Firme por Garantía de Suministro, salvo contingencias o condiciones extraordinarias debidamente justificadas o fuerza mayor, el DNC deberá reducir la Disponibilidad Comprometida para Garantía de Suministro a la disponibilidad verificada histórica promedio en los últimos doce meses, recalculando su Potencia Firme de Largo Plazo e informar al Participante.

Si como consecuencia de la reducción en su Potencia Firme de Largo Plazo, un Participante Productor resulta con menos Potencia Firme de Largo Plazo que la que ya tiene comprometida en venta por contratos y Servicio de Reserva Nacional, deberá antes de finalizar el año, comprar por Contratos de Respaldo la Potencia Firme de Largo Plazo faltante.

Antes de la finalización de cada año, el DNC deberá verificar para cada Participante Productor si dispone de suficiente Potencia Firme de Largo Plazo comercializable para cubrir sus compromisos de ventas de Potencia Firme por contratos y Servicio de Reserva Nacional. De resultar con faltantes en uno o más meses, se le asignará como un requerimiento de Reserva Anual a licitar para dichos meses.

5.- Resultados numéricos preliminares

Se realizaron algunas simulaciones considerando los cálculos para el año 2018 (Año $n+2$), y una falla del 1 %, resultando los siguientes valores para la Potencia Firme de Largo Plazo de las fuentes renovables:

Los resultados pueden tener variaciones en función de las hipótesis, aunque a nuestro juicio los resultados más consistentes se ubican en los valores mínimos que se detallan a continuación

Potencia Firme Hidráulica: 60 % de la potencia Instalada

Potencia Firme Eólica: 19 % de la potencia instalada

Potencia Firme Fotovoltaica: 6% de la potencia instalada

6.- Conclusiones

Desde diversos ángulos se puede asegurar que la energía eólica y la energía solar fotovoltaica aportan potencia y/o energía firme al abastecimiento de la demanda de un sistema eléctrico.

Asimismo, generan complementariedades y sinergias, especialmente con los almacenamientos hidroeléctricos lo que permite aumentar su valor agregado.

Claramente, su incorporación a la oferta permite desplazar la instalación de potencia térmica (a la que se le reconoce mayores niveles de firmeza en todo sistema eléctrico) y por tanto disminuye la volatilidad de precios del conjunto al aumentar la participación de generación con costo variable nulo.

También, como puede demostrarse, las energías renovables no convencionales aportan generación en momentos críticos del sistema eléctrico (definido como aporte en semanas de mayor demanda, u horas del día críticas, por ejemplo).

El sistema eléctrico uruguayo, que tiene una histórica y muy alta participación de las energías renovables en su matriz, ya reconoce el aporte de una fuente con altos niveles de aleatoriedad como la hidráulica. El manejo y la valuación adecuada de esta aleatoriedad no deberían generar inconvenientes para la incorporación a la reglamentación de la energía eólica y la solar fotovoltaica.

Ninguna tecnología tiene firmeza 100%, con distintos grados, el contar con la generación disponible en el momento requerido está sujeto, siempre, a probabilidad.

El reconocimiento adecuado y justo de la potencia firme de las ERNC es especialmente importante para que no se generen des-optimizaciones del portafolio de oferta.

Efectivamente, si no se reconociera adecuadamente la potencia que aportan estas tecnologías, para mantener los niveles de confiabilidad exigidos, se estaría incorporando al sistema más potencia firme (térmica) de la requerida, y por tanto generando una importante sobre-inversión. Esta sobre inversión, que genera un sobre costos, será definitivamente pagada en principio por quienes deban instalarla y más tarde el consumidor final de la energía.

Uruguay ha hecho un cambio relevante en su matriz energética, avanzando hacia una muy fuerte participación de las Energías Renovables No Convencionales. Esto implicó entre otros análisis, el evaluar cómo se comportaría el sistema para la gestión de aleatoriedad, y el impacto en las necesidades de firmeza en el sistema. Las decisiones tomadas, así como el resultado práctico de la implementación, refuerzan el punto de que el sistema con la incorporación de energía eólica y solar fotovoltaica requiere de menos potencia térmica. En los hechos se ha demorado la entrada el servicio del Ciclo Combinado de UTE, se han dado de baja máquinas térmicas del sistema; y aun sin incorporar todo el plan de renovables, ha mejorado la confiabilidad del sistema.

Por último, es necesario destacar que los sistemas regulatorios tienen un impacto directo en la atracción de inversiones y capital de riesgo; y en la mejora de la competitividad del sector y del país.

Un trato equitativo a todas las tecnologías permite un aumento de valor del conjunto del sistema, a través de asegurar tanto las futuras inversiones como una adecuada diversificación de las mismas.

7.- Anexos

EQUIPO DE TRABAJO

A continuación se presenta el Curriculum Vitae resumido del equipo de trabajo.

Dr. Ing. Mario Vignolo
Director de Clerk



Ingeniero Electricista egresado de la Facultad de Ingeniería – UdelaR. Realizó posteriormente su Maestría en Sistemas Eléctricos de Potencia con énfasis en los aspectos técnico-económicos de la Industria Eléctrica en un Mercado Competitivo (Power Systems Economics), en la Universidad de Manchester (UMIST) - Manchester, Reino Unido. Obtuvo luego su Doctorado en régimen mixto entre la Facultad de Ingeniería, Universidad de la República y el Public Utility Research Center de la University of Florida, EE.UU, especializándose en Mercados Eléctricos, siendo el objeto de su Tesis los aspectos económicos y regulatorios de la Generación Distribuida. Posee además diploma de Postgrado en Economía (Facultad de Ciencias Económicas –UdelaR) y es Técnico en Sistemas de Gestión de la Calidad UNIT- ISO 9000.

Trabajó como Ingeniero Consultor de UREE/URSEA entre los años 2001 y 2004, y desde 2005 como Ingeniero consultor independiente en el área de energía e ingeniería eléctrica, asesorando a diversas empresas nacionales e internacionales: MURACCIOLE LTDA (AREVA - ALSTOM), MONTES DEL PLATA, AKUO ENERGY, PALMATIR, NORDEX, PARQUES EÓLICOS LUZ DE MAR-LUZ DE LOMA-LUZ DE RIO, ENCE, CPE, CSI, MERCADOS ENERGÉTICOS, PNUD-CEBH (Paraguay), ECONOLER (Canadá), PONLAR, RIOGAS, MONTEVIDEO REFRESCOS S.A., PUNTA CARRETAS SHOPPING, STILER, TEYMA, VENTUS, SADAN y XDT Ingeniería.

Desde el año 1992 es docente de la Facultad de Ingeniería – UdelaR, siendo actualmente Profesor Agregado (Gr. 4) y Jefe del Departamento de Potencia del Instituto de Ingeniería Eléctrica de la Facultad de Ingeniería – UdelaR. Como parte de su actividad docente dicta diversos cursos de Grado y de Postgrado, siendo el responsable del curso de Postgrado “Introducción a los Mercados de Energía Eléctrica”.

Fue además, Profesor en Facultad de Arquitectura, Universidad ORT, en cursos de Acondicionamiento Eléctrico e Infraestructura Urbana, desde 2001 a 2007.

Es Senior Member del PES (Power and Energy Society) de IEEE y fue Presidente del Capítulo de Potencia, Instrumentación y Medidas del IEEE desde enero de 2004 a diciembre de 2006.

En el marco de su actividad académica, ha dirigido y tutorado más de 20 Tesis de Grado y de Postgrado y ha publicado más de 40 trabajos en Congresos Internacionales y revistas arbitradas y es coautor del libro “Una aplicación metodológica para el desarrollo eléctrico del Uruguay. La función eléctrica y el análisis multidimensional”, 2011. ISBN: 978-9974-631-36-6. Ha participado y/o dirigido además más de 10 proyectos de Investigación en el área de la Ingeniería Eléctrica (Generación Distribuida, Mercados Eléctricos, Calidad de Energía, Iluminación y Generación Eólica y Solar Fotovoltaica), siendo además actualmente responsable de los grupos de investigación en Calidad de Energía y Energía Solar Fotovoltaica en el Departamento de Potencia del Instituto de Ingeniería Eléctrica de la Facultad de Ingeniería de la UdelaR.

Alejandro R. Perroni Gonzalez
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Actualmente ocupa las siguientes posiciones:

Asesor en Mercados Energéticos de Acodike S.A.
Director de Gas Uruguay S.A.
Director de Astidey S.A. (Parque Eólico Talas del Maciel)

Fue Gerente General y Gerente Económico Financiero de la Administración Nacional de Usinas y Trasmisiones Eléctricas (UTE)

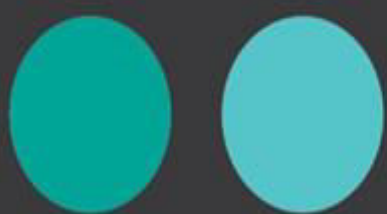
Fue Presidente de la Comisión Energética Regional (CIER)

Integrante del Observatorio de Energía y Desarrollo Sustentable de la Facultad de Ingeniería y Tecnología de la Universidad Católica del Uruguay

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Es co-autor del libro **La función eléctrica y el análisis multidimensional** editado por Universidad Católica del Uruguay



e



Integration of large amounts of wind energy in Uruguay



PICTURE "SIERRA DE LOS CARACOLAS" WIND FARM, URUGUAY FROM WIKIPEDIA



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I nt egrat ion of large am ount s of wind energy in Uruguay

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APPENDICES

Appendix A Explanation of calculations with hydro power
including description of "peak - loading"

Appendix B A description of how to handle dry year situation
concerning LOLP calculation

1 Introduction

Inter-American Development Bank (IDB) has entered into contract with COWI A/S with the purpose of assisting the Ministry of Industry, Energy and Mining (MIEM) of Uruguay with analysing some aspects of integrating large amounts of wind energy into the power system of Uruguay. The focus is on capacity credit with regard to system planning and on grid access regulation. Within these two components, the following activities are carried out:

- › Component 1 - Capacity credit of the wind energy resource
 - › Review of international experiences
 - › Review of methodologies to determine firm capacity / capacity credit
 - › Methodology to be used for the Uruguayan system
 - › Calculation of the firm capacity contribution
 - › Analysis and implications of the firm capacity contribution
 - › Recommendation on regulatory guideline
- › Component 2 - Grid access regulation
 - › Review of international experiences
 - › Review of methodologies to determine merit order

This report presents the results of the study.

2 The Uruguayan electricity market

2.1 Current situation

The annual electricity demand in Uruguay in 2012 was 10.1 TWh. In 2010, the consumption was 9.7 TWh and in 2011, the consumption was 9.8 TWh. The peak demand in 2012 was 1,742 MW. Approximately 70% of the demand is in the south region - the area covering Montevideo and being the most densely populated area.

The electricity demand has increased over time. In 1984 the demand was 3.7 TWh which means that since that time, the annual average increase in the electricity demand has been 3.7 %.

The annual Uruguayan power generation corresponds more or less to the demand. In 2010, there was a **net export** of 324 GWh corresponding to 3.3 % of the demand, and in 2011 there was a **net import** of 451 GWh corresponding to 4.6 % of the demand.

Due to a large amount of hydro power, the import/export patterns are very much influenced by the hydrological conditions, which can vary a lot from one year to another. In 2010, the generation from hydro power plants was 7,909 GWh and in 2011 it was 6,326 GWh.

In addition to hydro power plants, Uruguay has a number of thermal power plants based on fuel oil and gas oil and a few biomass plants and wind turbines.

The total installed power capacity in 2011 is shown in the table below.

Table 1: Installed power capacity, 2011

	Type	Fuel	Capacity, MW
Hydropower			1,538
- Salto Grande	Hydro with storage	-	7 x 135 = 945
- Rincon del Bonete	Hydro with storage	-	4 x 38 = 152
- Baygorria	Hydro run of river	-	3 x 36 = 108
- Palmar	Hydro with storage	-	3 x 111 = 333
Thermal			830
- Quinta	Steam turbine	Fuel oil	1 x 80
- Salab	Steam turbine	Fuel oil	1 x 50
- Sexta	Steam turbine	Fuel oil	1 x 120
- CTR	Gas turbine	Gas oil	2 x 100
- PTI	Gas turbine	Gas oil	6 x 50
- Motores	Internal Combustion	Fuel oil / Gas oil	8 x 10
Biomass	-	-	90
Wind Power	-	-	42

It appears from the table that hydro power accounts for approximately 60 % of the total capacity. The hydro power plants all have storage capacity, but the storage capacity is limited and therefore there is a huge variation in hydro power generation from one year to another. The hydro storage capacity is 3-4 months for Rincon del Bonete and 10-15 days for Salto Grande.

The largest hydro power plant, Salto Grande has a total capacity of 1,890 MW. This plant, however, is a bi-national plant with Argentina and therefore the Uruguayan part is only 945 MW corresponding to 50 % of total plant capacity.

Uruguay has interconnections with Argentina and Brazil, and power exchange takes place with both these countries. A map of the interconnections is shown below.

Figure 1: The Uruguayan transmission system including interconnections to Argentina and Brazil



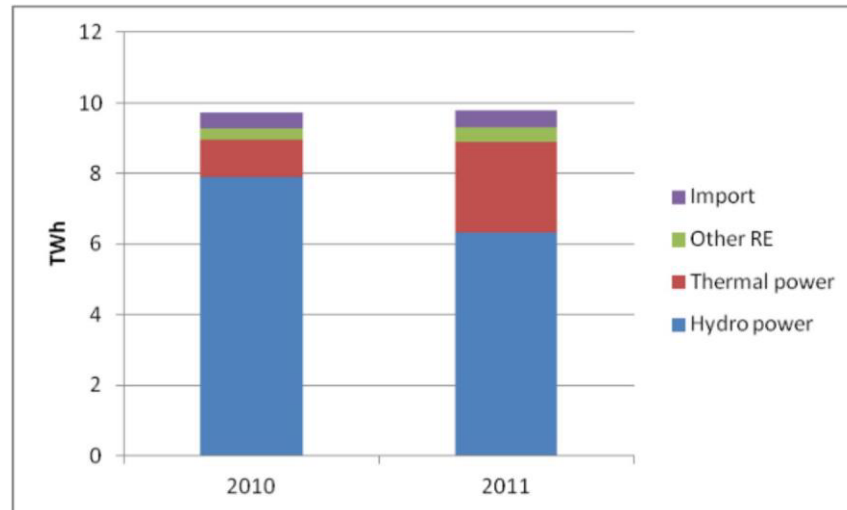
The current interconnections are:

- > 2,000 MW AC link with Argentina
- > 70 MW/150 kV link with Brazil through back to back frequency converter (50-60 Hz)

From 2014 there will also be a 500 MW/500 kV link with Brazil through back to back frequency converter (50-60 Hz).

The distribution of the Uruguayan power demand on generation sources in 2010 and 2011 is shown in the figure below.

Figure 2: Power demand distributed on generation sources



2.2 Future situation

Uruguay has the following planning goals for 2015:

- › Primary energy matrix: 50% participation of renewable energy.
- › Electricity from non-conventional renewable energy – 25% (Wind Energy and Biomass)
- › Reduction of oil participation.
- › Use of LNG.

According to the Traditional Energy Planning Study for the period 2012 to 2030, the Uruguayan electricity demand is expected to increase in average 3.48 % per year up to 2030. In 2017, the annual electricity demand has been estimated to 12,050 GWh and in 2030 it has been estimated to 18,775 GWh.

In the same planning study, a new capacity (after 2011) of 120 MW biomass, 1,300 MW wind power, and 480 MW combined cycle was assumed up to year 2017. After 2025, an amount of additionally 360 MW gas combined cycle should be installed. As of today 42 MW of wind is installed but contracts for additional 1,000 MW has been signed. In addition to the already contracted wind power generation capacity additional capacity can be expected from UTE and smaller wind developers. As a result of all these contracts and the additional capacity from UTE, a total of 1,000 MW of wind power is expected to be installed by 2016.

This large amount of wind power will impose new challenges for the safe and sustainable operation of the Uruguayan power system with today 2,700 MW installed capacity and a peak demand of 1,745 MW. The amount of 1,000 MW wind power will depending on the wind resources, and thereby the capacity factor, generate an annual amount of wind power corresponding to app. 25 % of the

annual power demand. The average capacity factor for the wind turbines is expected to be app. 39-40%.

3 Capacity credit of the wind energy resource (component 1)

When installing wind turbines in a power system, the main benefit is most often caused by the fuel savings at thermal power plants in the system. If the wind turbines for instance generate 3,500 MWh electricity per year, and this amount of electricity can be absorbed by the grid, the power generation at thermal power plants can be reduced more or less correspondingly¹ and the annual fuel savings may be in the range of 10,000 MWh per year, depending on the type of power plants and their electrical efficiency. This results in an economic as well as an environmental benefit.

In addition to the benefit from saved fuels in the system (and also some other benefits, see section 3.2.1), variable generation such as wind generation can also have a contribution to the **firm capacity**. This contribution is also known as the **capacity credit** or the **capacity value** of the wind energy resource and is normally estimated by determining the capacity of conventional plants displaced by wind power whilst maintaining the same degree of system reliability. The displacement of conventional plants in the system will, in addition to the benefit from the fuel savings mentioned above, result in an economic benefit, mainly due to lower investment/capital costs.

The definition of capacity credit does not take into account dynamic aspects from system operation like short term spinning reserve which should require additional considerations when comparing wind generation with other technologies. However, the large challenge in power systems is normally not spinning reserve and especially not in systems with much hydro power.

The capacity credit of the wind energy resource should not be confused with the **capacity factor** of wind turbines. The capacity credit is about wind turbines' contribution to the system capability to match the power demand at every moment and can be expressed in for example MW. The capacity factor is about wind turbines' contribution to generating electrical energy (their primary function) and

¹ Depending on any differences in network losses

can be expressed in for example MWh per year. If the capacity factor for instance is 30%, the expected annual generation from 1 MW installed capacity of wind will be $1 \text{ MW} * 8760 \text{ hours/year} * 0.3 = 2.628 \text{ MWh/year}$.

The capacity credit of the wind energy resource depends on many different aspects including among others the geographic spread of the wind turbines. As part of component 1 (this section) and based on probabilistic studies concerning planned and unplanned outages of thermal and hydro generation, load profile, and local wind speed variability, the contribution of installed wind generation to the firm capacity of the system in Uruguay will be analysed for a number of different scenarios.

The section is structured in the following sub sections:

- › Review of international experiences
- › Review of methodologies to determine firm capacity
- › Methodology to be used for the Uruguayan system
- › Calculation of the firm capacity (capacity credit)
- › Analysis and implications of the firm capacity contribution
- › Recommendation on regulatory guideline

3. 1 Review of international experiences

3.1.1 Europe

In Europe, system operators have the responsibility to maintain system adequacy at a defined high level. In other words, they should ensure that the generation system is able to cover the peak demand, avoiding loss-of-load events for a given security of supply. Every country has its own detailed method to assess the system adequacy. As the whole European system is interconnected, it is logical that national TSO's harmonise their approaches, which is mainly done under the umbrella of the larger systems such as UCTE, Nordic system, UK and Ireland system. The assessment methods of generation adequacy can be simulation or probabilistic, or a mix of the two – see 3.2.3.

In the estimation of the adequacy, each power plant is assigned a typical capacity value. This takes into account outages, scheduled and unscheduled. No plant has a capacity value of 100 %, because there is always the probability that it will not be available when required. By making a system-wide reliability assessment, it is possible to rely partly on variable-output generation (such as e.g. wind) as well. In Europe, however, there is not yet a proper standard amongst the TSOs for the determination of wind power's capacity credit.

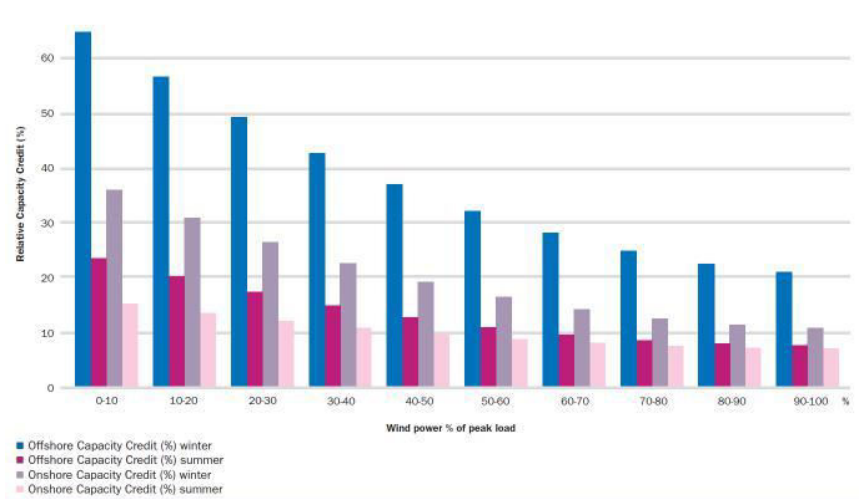
Despite the variation in wind conditions and system characteristics among the European countries and regions, capacity credit studies converge to similar results. For small penetrations, the relative capacity credit of wind power will be equal or close to the average production (capacity factor) during the period under consideration. When increasing penetration levels of wind energy in the system, its relative capacity credit becomes lower.

The table below summarises the factors leading to higher or lower levels of capacity credit. The differences in results from various national studies can be better understood, when looking at these factors. For example, in a UK study the capacity credit of wind is significantly higher than the one found in a German study. This is explained by the fact that the average wind speeds in the UK are much higher than in Germany, and moreover, the assumed system reliability in the UK study (91 %) was much lower than in the German study (99 %).

Table 2: *Factors affecting positively and negatively the value of the capacity credit of a certain amount of wind power in the system*

Higher capacity credit (%)	Lower capacity credit (%)
Low penetration of wind power	High penetration of wind
Higher average wind speed, high wind season when demand peaks	Lower average wind speeds
Lower degree of system reliability	High degree of system reliability
Higher wind power plant (aggregated) load factor (determined by wind climate and plant efficiency)	Lower aggregated capacity factor of wind power
Demand and wind are positively correlated	Demand and wind uncorrelated
Low correlation of wind speeds at the wind farm sites, (often related to large size area considered)	Higher correlation of wind speeds at wind farm sites, smaller areas considered
Good wind power exchange through interconnection	Poor wind power exchange between systems

Figure 3: Average capacity credit for different values of wind (capacity) penetration for different situations: offshore/onshore, summer/winter.



Source: EWEA, 2005

Integrating wind

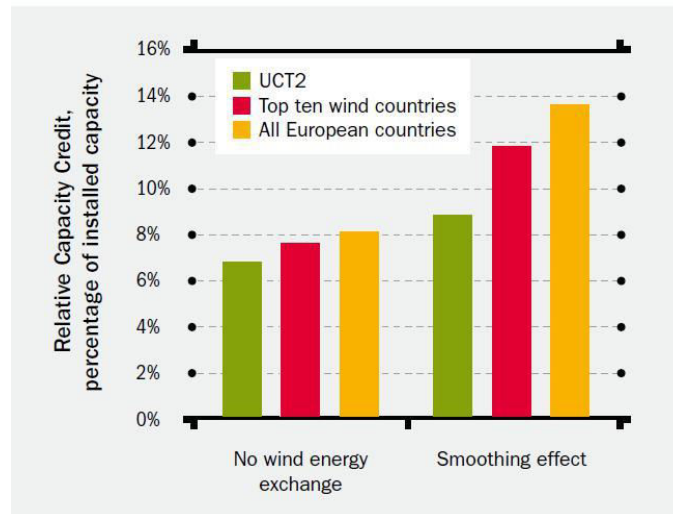
Joining together, or "aggregating" wind energy production from several countries, strongly increases wind power's contribution to firm capacity in the system. The larger the geographical area represented by the grouped countries, the higher the increase of the capacity credit. In an European study (TradeWind, 2009), the effect of aggregating wind energy across multiple countries almost doubles the average capacity credit compared with the capacity credit averaged over separate countries.

The capacity credit of wind power was calculated as the difference between the firm capacity of the system with and without wind energy, maintaining supply security level of 99 %. The capacity credit of wind power for individual countries was calculated from country specific wind energy time series, using seven wind years (2000-2006), and wind power capacity values corresponding to a medium scenario for 2020. The final result was considered to be the minimum capacity credit of the seven years.

The effect of wind power aggregation was the strongest when wind power was shared by all European countries. At EU level without wind energy exchange, the total capacity credit was found to be 8 %. When the countries were aggregated, this figure increased by a factor 1.75 to reach 14 %.

This is frequently referred to as smoothening effect which basically depends on how well developed the grid system is and the extent to which different wind regimes can be observed within the system evaluated.

Figure 4: Increase in the capacity credit in Europe due to wind energy exchange between countries in 2020 (12 % wind penetration). UCT2 covers Germany and France.



Source: TradeWind, 2009

3.1.2 South Africa

In South Africa, the Department of Energy has commissioned a study on the capacity credit of wind generation in South Africa. The purpose of the study was to assess the capacity credit of planned wind farms in South Africa and the impact of wind generation on the required dynamic performance of the thermal and hydro power plants.

The analyses were carried out for different scenarios and by use of a Monte Carlo analysis approach considering:

- › Daily peak load characteristics
- › Planned and unplanned outages of conventional generators
- › Correlation of wind speed at different sites
- › Daily, weekly and monthly correlation between wind speeds and the daily peak load.
- › Correlation between wind speeds and daily full load hours

The study has shown that besides contributing to the electrical energy supply, wind turbines can also have a valuable contribution to the equivalent firm capacity of a system. This means in other words, that with the addition of wind farms, the reliability of supply of a system is improved and that it is indeed possible to replace some conventional power plants by wind farms completely.

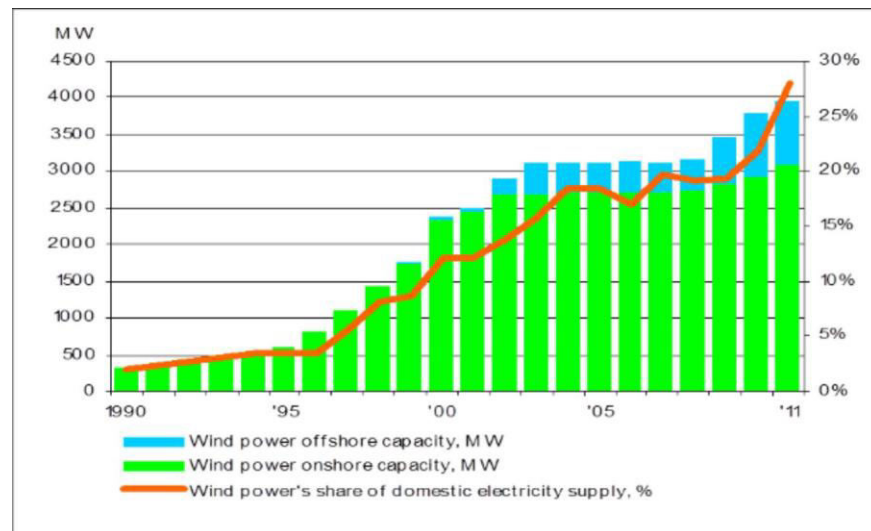
The conclusion was that the sites with best wind conditions may not be developed first, but factors such as surrounding infrastructure may be just as important in project developments. When considered in connection with a typical coal fired power station in South Africa, results showed that to have the same effect on generation capacity, the installed capacity of a wind farm must be approximately 3 to 4 times higher than the installed capacity of a coal fired plant. Overall, for a wind generation plant in South Africa, the capacity credit of wind generation will be between **25 % and 30 %** for installed wind generation of up to 10,000 MW. In the case of higher wind penetration (25,000 MW), the capacity credit of wind generation in South Africa will drop below **20 %**.

The wind penetration levels of the different scenarios varies between around 5 % and 20 % (based on peak load), which can be considered to be moderate, even in the scenario with 20 % penetration.

3.1.3 Denmark

Denmark has approximately 4,000 MW wind turbines installed and an annual electricity demand of approximately 32 TWh. The wind turbines cover 25-30 % of the annual electricity demand. The figure below shows the development in installed wind power capacity from 1990 to 2011 and the wind power's share of domestic electricity supply.

Figure 5: Wind power capacity and wind power's share of domestic electricity supply



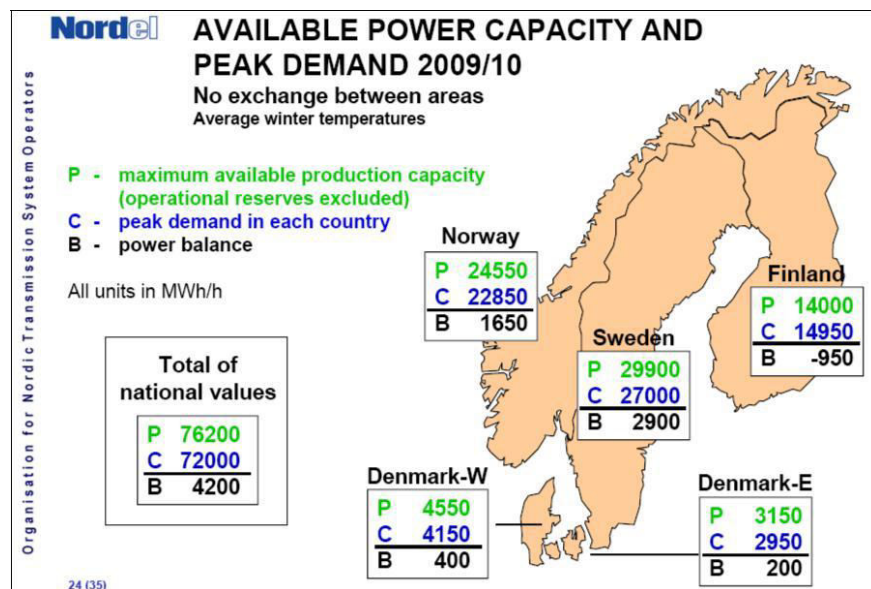
Source: The Danish Energy Agency

In Denmark, the capacity credit from wind turbines has not yet been an issue, and actually a value of only 0 % is used in capacity balances. This is mainly because the capacity balance, i.e. the ratio between installed power capacity and peak demand, has been quite good for many years, also without taking the capacity from wind turbines into consideration. Furthermore, Denmark has very strong interconnections to neighbouring countries, including Norway with large amounts

of hydro power with storage capacity, and the power exchange takes place through a well-developed and well-functioning electricity market (NordPool).

The figure below shows the capacity balance in the Nordic countries. Norway and Sweden are the only countries among these countries which include wind power when considering the capacity balance. Norway and Sweden use a capacity value for wind power of 10 % and 5 %, respectively. Both Denmark and Finland use 0 %.

Figure 6: Capacity balance in Nordic countries, 2009/2010



Source: Nordel

3.1.4 US

In the United States, the question of wind's capacity value is gaining more attention. Wind's low cost and environmental benefits, and the higher costs of competing fuels, mean that system planners will need to grapple with how to determine the capacity value of wind energy. It does seem clear that wind's primary value is as an energy resource, but to the extent to which it contributes towards system adequacy is an important question.

Wind generators typically have a very high mechanical availability, exceeding 95 % in many instances, i.e. the forced outage rate is often below 5 %. However, because wind generators only generate electricity when the wind is blowing, wind's availability rate (the rate that power and energy can actually be provided) is a function of the wind speed throughout the year.

In the United States there are different methods to assess wind capacity credit, also depending on whether the calculated capacity credit should be used for system planning which require some detailed calculations or for capacity payment which may allow for some more pragmatic approaches.

One method is to determine the contribution that a certain amount of wind power makes to overall system adequacy. This is a straightforward process and has been well-known for several decades. The approach results in a capacity contribution that is called the Effective Load Carrying Capability (ELCC). To calculate ELCC, a database is required that contains hourly load requirements and generator characteristics.

Because of the potential difficulty of assembling the appropriate data for doing the Loss Of Load Probability LOLP calculations, interest in simpler methods has emerged over the past several years. Many utilities, ISO's, and RTO's in the United States use peak period methods for assessing the wind capacity value. These methods require less data than the LOLP calculations; however an unfortunate aspect of these methods is that they are indeed an approximation (see also section 3.2.3).

An overview of different wind capacity values in the United States is shown in the figure below.

Table 3: *Wind capacity value in the United States*

Region/Utility	Method	Note
CA/CEC	ELCC	Rank bid evaluations for RPS (mid 20s); 3-year near-match capacity factor for peak period used by CA PUC and CA ISO
CPUC	Peak Period	Three-year rolling average of the monthly average of wind energy generation between 12 and 6 p.m. for the months of May through September.
PJM	Peak Period	Jun-Aug HE 3 p.m. -7 p.m., local time, capacity factor using 3-year rolling average (13%, fold in actual data when available).
MN 20% Study	ELCC	Found significant variation in ELCC: 4%, 15%, 25% and variation based on year
ERCOT	ELCC	ELCC based on random wind data, compromising correlation between wind and load (8.7%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26-34%)
NY ISO	Peak Period	Wind's capacity factor between 2-6 p.m., June through August, and 4-8 p.m., December through February
CO PUC/Xcel	ELCC	12.5% of rated capacity based on 10-year ELCC study. Load forecast algorithm compromised correlation between wind and load
PacifiCorp	ELCC	Sequential Monte Carlo (20%). Z-method 2006
MAPP	Peak Period	Monthly 4-hour window, median
Idaho Power	Peak Period	4 p.m. - 8 p.m. capacity factor during July (5%)
Nebraska Public Power District		17% (method not stated)
Northwest Resource Adequacy Forum	Rule of Thumb	15%. Being studied further for potential revision.
Tri-State	Peak Period	2-12%. Appears to be based on wind's contribution to monthly coincidental peak.
SPP	Peak Period	Top 10% loads/month; 85th percentile
PNM	Peak Period	Capacity factor between 4-5 p.m. in July
ISO New England	Peak Period	For existing wind: wind's capacity factor between 2-6 p.m., June through September and 6-7 p.m. from October through May. For new wind: based on summer and winter wind speed data, subject to verification by ISO New England and adjusted by operating experience.

Source: NREL (National Renewable Energy Laboratory)

3.1.5 Colombia

Colombia has developed a financial mechanism to produce an economic signal to investors as a price premium on reliable installed power capacity. This instrument aims at increasing the resilience (firmness) of the national interconnected system to extreme weather events, especially during unusually dry periods. The reliability payment, or firm capacity charge, should promote an efficient mix of energy sources, without discriminating renewable sources.

Until recently, wind power was not eligible for a firm energy payment in Colombia. In July 2011 however, CREG released a proposal for measuring ENFICCs² for wind plants based upon the historical experience of EPM's Jepirachi plant. Following a broadly similar methodology to that applied to hydro plants, the CREG used historical generation data from 2004 to 2011 to estimate monthly capacity factors for the Jepirachi wind farm, and derived an ENFICC Base of 6 % and an ENFICC 95 % PSS (the amount of energy the plant can be relied upon to produce with 95 % probability) of 7.3 %.

In its July 2011 document and in its subsequent draft Resolution 148 of October 2011, the CREG suggest two alternative methods for calculating ENFICCs for wind plants; one for plants that have less than 10 years of information on wind resources, and another for plants that have at least 10 years of information. In the first case, they use the operating experience from Jepirachi as the basis for determining the ENFICCs for a new wind power plant, i.e. 6 % ENFICC BASE and 7.3 % ENFICC 95 % PSS.

For plants for which there is more than 10 years of wind data, they use the following formula:

$$E = \min (24 \cdot 1000 \cdot k \cdot v^3; 24 \cdot 1000 \cdot CEN \cdot (1 - IHF))$$

Where:

E: energy (kWh/day)
 k: conversion factor for wind plants
 v: average monthly wind speed (m/s)
 IHF: historic forced outage rate
 CEN: Effective net capacity (MW)

With this formula, the CREG constructs a probability distribution curve, from the lowest to the highest level of firm energy, using monthly values. The lowest firm energy factor corresponds to a 100 % probability of it being exceeded and the highest value has a 0 % probability of being exceeded.

² ENFICC = Energía Firme para el Cargo por Confiabilidad. ENFICC refers to the amount of energy a generator of a given type can reliably and continually produce during periods when hydro generating capacity is at a minimum.

The World Bank study, on the other hand, suggested measuring ENFICCs for wind plants using the following exponential smoothing formula under which the “firm energy rating” (the ENFICC) is updated annually:

$$\text{Firm energy rating in } t+1 = (\text{firm energy rating in } t) + (\text{energy produced in year } t),$$

The firm energy rating for the initial year t could be based on recent data; for instance, plants located on the northern coast could use the period of generation recorded by Jepirachi. According to the World Bank, the firm energy rating will adjust quickly to the long run average level of firm energy capability, even if the initial estimate is wrong.

Applying their formula to a 24-year series of monthly wind and production data related to the Jepirachi plant, the WB estimated an average annual firm energy rating of 38 %, with a range between 25 % and 47 %. They also estimated a firm energy rating for dry seasons of 40 %, with a range from 30 % to 47 %.

The difference of these two approaches (WB and CREG) is significant when measured in terms of the financial consequences.

3.1.6 Mexico

In Mexico, one of the large national utility companies, CFE, has been reluctant to invest in wind energy facilities due to concerns about the economics and intermittency of wind power. Apart from large hydropower, the only RE power that CFE was willing to consider was geothermal, because it offered firm capacity and could be dispatched on demand. In 2002, the Ministry of Energy (SENER) issued a policy directive requiring CFE to finance its own wind power generation. This mandate from SENER allowed CFE to proceed without having to show least cost.

Whereas the initial SENER directive focused on overcoming reluctance by CFE to include wind in its generation portfolio, much of the new electric capacity in Mexico was being built by IPPs that was building natural gas combined cycle units and was inexperienced with wind farms. To build this experience, while also developing CFE's institutional capacity to value, acquire and manage renewable energy resources, and to make the costs more competitive with conventional power supply options, the government of Mexico issued additional instructions to CFE to contract for renewable energy capacity and obtained a \$70 million grant from the Global Environment Facility (GEF) through the International Bank for Construction and Redevelopment. Through that fund, CFE could pay each IPP an additional incentive of up to 1.1 cent per kWh delivered (a feed-in-tariff) for the first five years of generation.

A key challenge, however, in fostering renewable energy through IPPs involved reaching agreement on the rules of payment. Normally, IPPs would be paid not only for the energy delivered, but also for their generation capacity, any amount of which could be requested by CFE at any time. However, CFE was unwilling to pay for capacity for intermittent sources. The main problem with wind IPPs is that the

IPPs cannot guarantee that the wind will blow when capacity is required by CFE, and therefore the capacity payment could not be treated in the same way as for a natural gas combined cycle unit. Finally, the decision was taken to base the capacity payment for wind on the available capacity during peak periods (on average each month) and simply include it as part of CFEs total payment per kilowatt-hour delivered to the grid, recognizing that when the power was delivered, it was because the capacity was available. This capacity payment, approved by the Energy Regulatory Commission in 2005, was important to make wind projects economically viable for IPPs.

3.2 Review of methodologies to determine firm capacity

The aim of a power plant in a power system is to supply the load in an economical, reliable and environmentally acceptable way. Different power plants can fulfil these requirements in different ways. This section will describe the different requirements on a power plant and how these requirements can be met with wind power.

3.2.1 The Value of a power plant

Different power plants have different characteristics concerning how they can be controlled in the power system. A common situation is that the value of a new power plant is considered to be the marginal value of the plant in an existing power system. The different types of value in relation to the new power plant are described below.

Operating cost value

Operating cost value is the capability of the new power plant to decrease the operating costs in the existing power system.

For instance, if a new power plant – more efficient / with lower variable costs than the existing ones – is added to the system, this power plant will supply energy to the system. This means that the energy production of other and less efficient / more expensive power plants in the existing system will decrease. The consequence is that the operating costs in these plants decrease.

Capacity credit

Capacity credit refers to the capability of the new power plant to increase the reliability of the power system.

One possible way to measure the reliability of a power system, is the so-called loss of load probability (LOLP), calculated as the risk of a capacity deficit in the system. This risk is in many systems, e.g. in OECD countries very low, but in some systems it can also be rather high. In the case of a capacity deficit, some load has to be disconnected. If a new power plant is added to this system there is a certain chance that customers do not have to be disconnected so often, since the installed capacity of the system increases. This implies that the reliability of the system increases, as a result of the new power plant.

Control value

Control value is a value related to the capability of the new power plant to follow the net-load, i.e., load minus production in variable power sources.

In a power system, there is a need for continuous production control, since total production always has to be equal to system load, including losses. Since load and some power sources vary continuously, the production in some controllable sources also has to vary continuously. This value is different for different power plants. It can also become negative if the new power plant increases the need for control in the system, as would often be the case for wind power plants.

Loss reduction value

Loss reduction value relates to the capability of the new power plant to reduce grid losses in the system.

Power transmission and distribution always causes grid losses. If power is transmitted over long distances and/or at low voltages, the losses are relatively high. If a new power plant is located closer to the consumers, compared with existing power plants, the losses in the system decrease, since the amount of transmitted power decreases. This implies that the new power plant has extra value related to its capability of reducing these losses. However, a negative value means that the new power plant increases system losses.

Grid investment value

Grid investment value refers to the capability of the new power plant to decrease the need of grid investments in the power system.

If a new power plant is located close to consumers exhibiting increasing demand the new power plant may reduce the need for new grid investments. This constitutes extra value in relation to this plant. Also, this value can be negative if the new power plant increases the need for grid investments.

3.2.2 The Capacity Credit of wind power

As stated in chapter 3.2.1, the value of a power plant can be divided into several sub values. In this chapter, the sub value "Capacity credit" will be described for wind power.

In any power system there is always a certain risk of capacity deficit, measured as Loss of Load Probability, LOLP. The used term is system adequacy, i.e., there should be enough capacity for the system needs. The level of this is different in different systems, and an indication of the level is how often there has been forced load disconnection caused by lack of available capacity for decades.

Definition of Capacity Credit

The capacity credit is defined as the possibility for a certain power plant to increase the reliability, measured as decreased LOLP, of the power system with a certain level. There are some slightly different definitions:

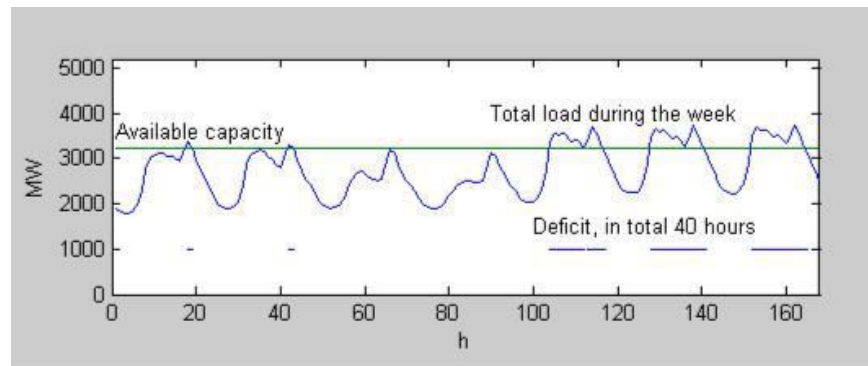
- › **Equivalent Load Carrying Capability- ELCC:** If X MW of a power plant result in that the demand can increase with Y MW at the same LOLP, then the capacity credit as ELCC of the X MW power plant is Y MW
- › **Equivalent Firm Capacity-EFC:** If X MW of a power gives the same decrease of LOLP as a 100 percent reliable Y MW power plant, then the capacity credit as EFC of the X MW power plant is Y MW
- › **Equivalent Conventional Capacity-ECC:** If X MW of a power gives the same decrease of LOLP as a conventional, not 100 percent reliable, Y MW power plant, then the capacity credit as ECC of the X MW power plant is Y MW

The basic theory of this was presented by Garver in IEEE Transactions on Power Apparatus and Systems in August 1966 in a paper with the title Effective Load Carrying Capability of Generating Units. The method and definition has also been applied to wind power since the end of the 1970s.

Illustration of wind power capacity credit

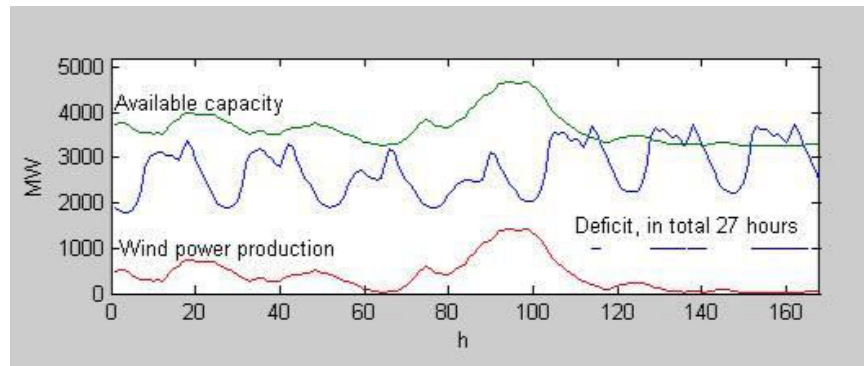
The capacity credit of wind power treats the possibility of wind power to increase the reliability of the power system. Figure 7 shows an illustrative example of a weekly load where the available capacity is 3200 MW. This implies that there will be capacity deficit during 40 hours in that week.

Figure 7: Occasions with capacity deficit without wind power



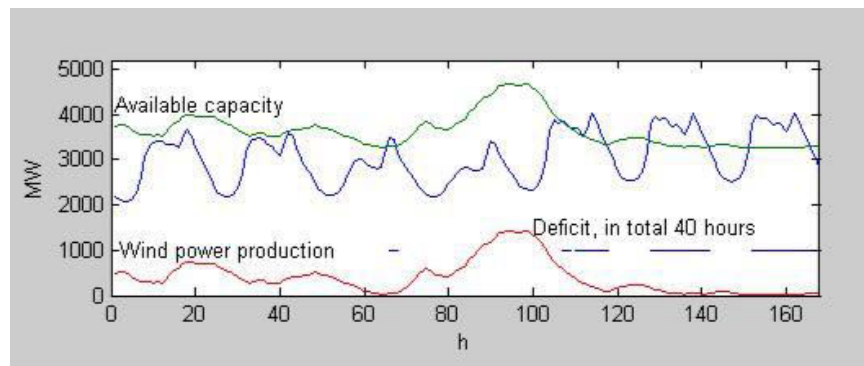
Wind power is now introduced in this system and that available capacity is increased according to Figure 8. In the figure real wind power has been scaled up to get a significant production level. The consequence of this amount of wind power is that the number of hours with capacity deficit has decreased to 27.

Figure 8: Occasions with capacity deficit with wind power



This means that the reliability of the power system has increased thanks to wind power, i.e. lower LOLP. Assume that the reliability was acceptable before wind power was installed. This implies that the power system can meet a higher demand with wind power if the same reliability level is accepted.

Figure 9: Occasions with capacity deficit with wind power and load +300 MW



In Figure 9 it is shown that if the load increases with 300 MW during each hour, then the number of hours with capacity deficit increases to 40. This implies that the capacity credit of the studied amount of wind power measured as equivalent load carrying capability is 300 MW.

It should be noted that Figure 7 to Figure 9 only provide an illustration of how to estimate the capacity credit. The risk of capacity deficit is normally much lower than the here shown figures, often much lower than 0.1%. It is also important to note that the risk of capacity deficit cannot be zero for this calculation since the reliability cannot be increased in this case, i.e. the capacity credit is zero for any power plant. It should also be noted that it is not only the peak demand that is of interest, but also other situations.

There remains the question of how wind power can have a capacity credit when there are situations with no wind? It has to be kept in mind that for any power source there is a risk that it is not available during peak loads. The method used here to define capacity credit is exactly the same as the method that is used to define the capacity credit for other sources (Garver, 1966). The example above shows that the number of hours with capacity deficit decreases, but not to zero,

when the amount of wind power increases. During hour 60, for instance, there is no wind, and it does not matter whether the amount of installed wind power capacity increases during this hour, since there is no wind. But the figures also show that during peak hours there is sometimes wind, which means that wind power can decrease the risk of a capacity deficit. In the figures, one week is used for illustrative purposes, but the data of a longer period, probably over several years, has to be used to be able to draw general conclusions.

3.2.3 Method for how to calculate the Capacity Credit of wind power

There are basically two different ways to calculate the capacity value of wind power: by **simulation** and by **probabilistic analysis**.

In **simulation methods** (not used in this project), the reliable operation of the system is observed and analysed by stepping through time-series data using simulation models. The results should be interpreted with care since single events tend to dominate the result. The most significant events are special combinations of load and wind speed, especially in the high load period. In order to grasp the effect of such special combinations in the simulation methods, a sensitivity analysis can be performed, shifting the time series of wind power against the load data in steps of days.

In the **probabilistic method** - which is the preferred method for system planning purposes - basically the availability of all power plant in the generation system is considered when the capacity credit for one of them is assessed. For instance, it is generally assumed that a coal power plant has an operational probability of about 96% and the probability of non-operational condition (scheduled or unscheduled) of 4%. This is denoted Forced Outage Rate, FOR. In order to take wind power into account, its capacity and probabilities have to be introduced into the model. The probability of generation of individual wind turbines is determined by the wind regime, an assumption which automatically induces a certain correlation between the power outputs of the individual wind turbines. A realistic representation needs to take smoothing effects into account, which arise from the geographical dispersion of wind farm locations. On the basis of the probabilities of individual power plants and the wind power, the probabilities of the whole generation system to cover different load events can be derived.

The probabilistic methods can be divided into the methods described in the previous section (ELCC, EFC and ECC), which are all based on calculation of the loss of load probability, LOLP (or alternatively LOLE³), as well as some more simple approximation methods, also called "Peak period" methods.

³ Sometimes LOLE (Loss of Load Expectation in days per year) is used as reliability metric for the system instead of LOLP (Loss of Load Probability in percent).

Methods based on LOLP

As shown above the capacity credit can be based on calculation of the loss of load probability, LOLP. The three different methods ELCC, EFC and ECC all use the basic method:

- a) Calculate LOLP(no wind) without wind power
- b) Add X MW of wind power and calculate LOLP(X MW of wind power)
- c) Add load (Y MW in ELCC) until LOLP(Y MW extra load)=LOLP(no wind). Or replace the wind power plant (with Y MW firm capacity in EFC), (with Y MW conventional capacity in ECC) until LOLP(with this Y MW power plant) = LOLP(X MW of wind power)

The result from these calculations is then that X MW of wind power has the capacity credit of Y MW. The LOLP can be calculated in the following way. We here assume

- › The demand is represented with a load duration curve, LDC
- › The conventional power plants have a certain availability, p_k , and an installed capacity, G_k
- › The method is denoted Probabilistic Production Costing, PPC, but here we only use the LOLP calculation and not the calculation of expected production and expected cost.

The fundamental PPC method is as follows. The method is based on the concept of “equivalent load”. The equivalent load is the sum of the load and outages, where outages, O , in a power plant is the difference between the installed capacity, IC , and available capacity, AC . For power plant nr k this then means

$$O_k = IC_k - AC_k \quad (1)$$

The Equivalent Load, EL , is the sum of Load, L , and Outages in all the K power plants, O_k :

$$EL = L + \sum_{k=1}^K O_k \quad (2)$$

We here treat load changes and outages in power plants as independent stochastic variables. This then means that the equation implies convolution. With probability denoted $p(\dots)$: The LOLP = risk of capacity deficit = risk that (the load > available capacity) = risk that (load > installed capacity – outages) = risk that (load + outages > installed capacity) = risk that (equivalent load > installed capacity), or

$$LOLP = p(L > \sum(G_k - O_k)) = p(L + \sum O_k > \sum G_k) = p(EL > \text{total inst.capacity})$$

(3)

So the challenge is then to estimate the “Equivalent Load Duration Curve” which can be obtained from equation 2 using convolution as

$$F_k(x) = p_k F_{k-1}(x) + q_k F_{k-1}(x - G_k) \quad (4)$$

where

$F_0(x)$ = Load Duration Curve in point x

P_k = availability of power plant k

$Q_k = 1 - p_k$ = unavailability of power plant k

G_k = installed capacity in power plant k

The method to calculate the LOLP is then:

Start with the Load Duration Curve, i.e., $F_0(x)$

Add one power plant (hydro or thermal) and calculate the next Equivalent Load Duration Curve, $F_1(x)$ with eq. 4.

Add one extra power plant at the time until the last Equivalent Load Duration Curve, $F_K(x)$, including all units is obtained with eq. 4.

The LOLP can then be read as $F_K(\text{Total installed capacity})$, c.f. eq. 3.

There are some issues that have to be considered in the calculation for wind power capacity credit:

- › When wind power is added one have to consider the correlation between wind and load. If one then have parallel data for several years, one can for each hour calculate:
 $\text{Net load (hour } j) = \text{Load (hour } j) - \text{total wind power (hour } j)$
 One will then add wind power by calculating the Net Load Duration Curve.
- › If the availability of conventional power plants is very different over the year, then one perhaps have to make LOLP calculations for different periods of the year and then weight them together.

Peak period methods

Because of the potential difficulty of assembling the appropriate data for doing the LOLP calculations, interest in simpler methods has emerged over the past several years. Many utilities, ISO's, and RTO's in the United States use peak period methods for assessing the wind capacity value. These methods require less data than the LOLP calculations; however an unfortunate aspect of these methods is that they are indeed approximations.

For instance in the PJM Regional Transmission Organisation, the capacity credit for wind is based on the wind generator's capacity factor during the hours from hours ending 3 p.m. to 6 p.m., local prevailing time, from June 1st through August 31st. The capacity credit is a rolling 3-year average, with the most recent year's data replacing the oldest year's data. Because of insufficient wind generation data, PJM has applied a capacity credit "class average" of 20% for new wind projects, to be replaced by the wind generator's capacity credit as noted earlier once the wind project is in operation for at least a year. As an example, a new wind generator will receive a capacity credit of 20% the first year, and for the second year, the average of the wind generator's capacity factor during the hours from 3 p.m. to 7 p.m. from June 1 through August 31 and 20%, weighed twice since there is only one year of operational data. For the third year, a wind generator will receive the average of 20% and the wind generator's capacity factor during the hours from 3 p.m. to 7 p.m. for June 1 through August 31 for years two and three, and so on. In May 2008, PJM replaced the 20% capacity credit class average with 13%, based on the average capacity factor during the 3 – 7 p.m. hours from June through August for all wind generators that have been in operation for three years or more in PJM. The revised capacity credit will take effect for the 2011/12 period; the 20% class average will remain in effect until then. A higher project-specific capacity credit may be obtainable if the wind developer provides evidence that the wind turbine design and wind patterns justify the use of a higher capacity credit than the PJM class average for wind.

Another example of the peak period method is the California Public Utilities Commission (CPUC). They have a local resource adequacy requirement that requires load-serving entities under the CPUC's jurisdiction to provide evidence that at least 90% of the capacity needed to meet demand is available, plus a planning reserve margin of 15% to 17%, on a year-ahead basis for the following May through September. The CPUC determines these capacity obligations annually. The monthly net qualifying capacity credit of wind is determined by the three-year average of monthly hourly production between noon and 6:00 p.m. on weekdays. For wind projects with less than three years of operation, a "class average" of all wind generation within a transmission zone will be used, supplemented with project-specific data when available. A CPUC staff paper determined that the monthly net qualifying capacity value of wind in summer 2007 ranged from 20% to 60% of nameplate capacity in June, to between 15% and 30% in July and August. There also was considerable variation between the different wind development areas.

3. 3 Methodology to be used for the Uruguayan system

The peak load methods as described in the previous section are most often used in connection with capacity payment to wind generators in countries/systems where the payment is divided into two parts, i.e., an energy part (money/kWh) and a capacity part (money/MW). However, when the capacity credit from wind generators is to be used for system planning purposes and for assessments of system reliability and system adequacy, the more accurate methods based on LOLP calculations should be used instead.

From the discussions during the kick-off meeting in February 2013, it became clear that the purpose of calculating the capacity credit for wind power in the Uruguayan system is for system planning. In Uruguay, the power demand is expected to increase in the coming years and at the same time some of the existing conventional generators will come to face their end of lifetime, as well as new conventional plants, like a 500 MW Combined Cycle GT will be commissioned. There is therefore a need for assessing the system reliability and for assessing how the planned wind turbines will contribute to the system adequacy.

Based on this, and due the fact that data needed for carrying out the LOLP calculations seems to be available, it is strongly recommended to use the methodologies based on these calculations, i.e., the ELCC, EFC or ECC methodology.

There is only a slightly difference in the definition of the three methods, ELCC, EFC and ECC. In order to illustrate the difference and because the LOLP calculation is basically the same for all three methods the capacity credit will be calculated by all three methods.

The recommended method uses hourly data for the whole year (demand data and wind data) and not only selected peak load data. This is important because it is not only the peak demand situation that is of interest, but also other situations.

As agreed during the kick-off meeting, the calculations of capacity credit will be carried out without taking the power interconnectors into consideration. Furthermore, as agreed during the kick-off meeting, the calculations of capacity credit will be carried out for three different scenarios with regard to the amount of wind power (penetration level), i.e., 800 MW, 1000 MW and 1200 MW. The 1000 MW is regarded as the base case with a variation of +/- 20% in installed capacity. The calculation method assumes as an approximation the same variation in production for all three scenarios with regard to amount of wind power and scales up and down the production each hour with the capacity installed.

The wind power production estimates are based on the assumption that there will be three large scale wind parks. That is not the case as there will be several smaller wind parks. This approximation is conservative as it reduces the smoothening effect – see 3.4.2 and 3.5 for wind production considerations.

As a first step all calculations will be carried out for the year 2016 by use of 2012 wind data, up scaled 2012 load data and without water limitations. Subsequently three specific years will be studied – a dry year an average year and a wet year – see 3.4.3

The main input to the calculations will be:

- › Hourly load profiles
- › Hourly wind production profiles

- › Installed capacities and availabilities for thermal and hydro generators in the system in 2016
- › A chosen system reliability requirement (corresponding to the one in the system with no wind which will be calculated)

The hourly load profiles as well as short term wind data have been provided by MIEM. In addition to these data, the consultant has been able to get long term wind data which correlates with the short term data.

The installed capacities and the proposed availabilities for thermal and hydro generators in the system in 2016 are shown in Table 4 below.

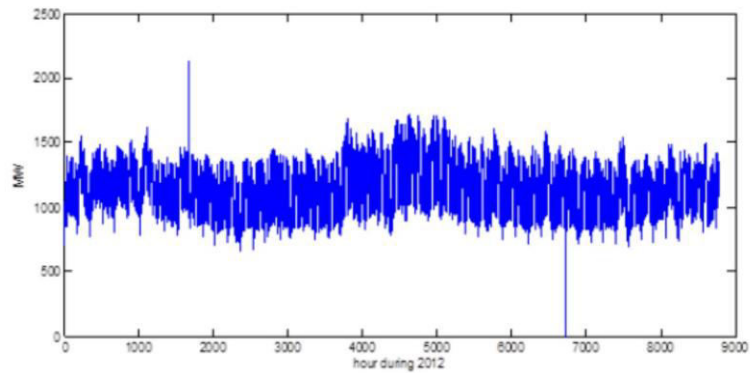
Table 4: *Installed capacities and availabilities for thermal and hydro generators in 2016*

	Type	Fuel	Capacity, MW	Availability, %
Hydro power			1,538	
- Salto Grande	Hydro with storage	-	945 (7x135)	99.5
- Rincón del Bonete	Hydro with storage	-	152 (4x38)	99.5
- Baygorria	Hydro run of river	-	108 (3x36)	99.5
- Palmarr	Hydro with storage	-	333 (3x111)	99.5
Thermal			1,330	
- New CC	Combined cycle	Natural gas	1 x 500	85
- Quinta	Steam turbine	Fuel oil	1 x 80	70
- Salab	Steam turbine	Fuel oil	1 x 50	45
- Sexta	Steam turbine	Fuel oil	1 x 120	70
- CTR	Gas turbine	Gas oil	2 x 100	70
- PTI	Gas turbine	Gas oil	6 x 50	70
- Motores	Internal Combustion	Fuel oil / Gas oil	8 x 10	80
Biomass	-	-	230	70
Total	-	-	3,098	-

3.4 Calculation of the firm capacity

This evaluation will first be based on load data and wind power data from 2012 to be representative for a situation in 2016. Available load data from 2012 are shown in Figure 10.

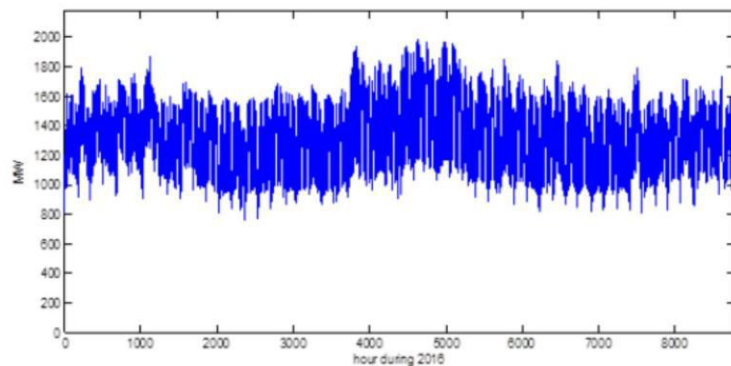
Figure 10: Load data from 2012



There are two extreme values. One up (2129 MW, day 71, 2nd hour = 2012-03-11, hour 1), and one down (0 MW, day 281, 2nd hour = 2012-10-07, hour 1). The origin for these two hours is the winter/summer official time change carried out every year at the second hour of the 1st Sunday of October and the 2nd Sunday of March. We will here replace them with the mean value of the previous and following hour.

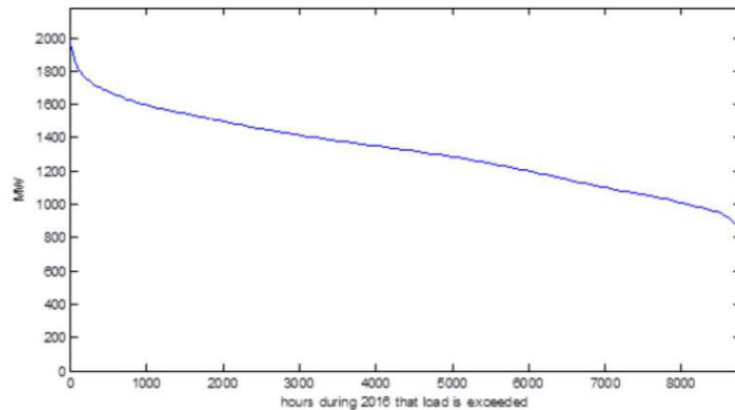
The load from 2012 to 2016 is assumed to increase with 3.7 % per year, i.e. multiply the load during each hour with 1.037^4 . The result is shown in Figure 11. The yearly energy consumption = the sum of all values = the area under the curve is 11.618 TWh.

Figure 11: Applied load data for 2016



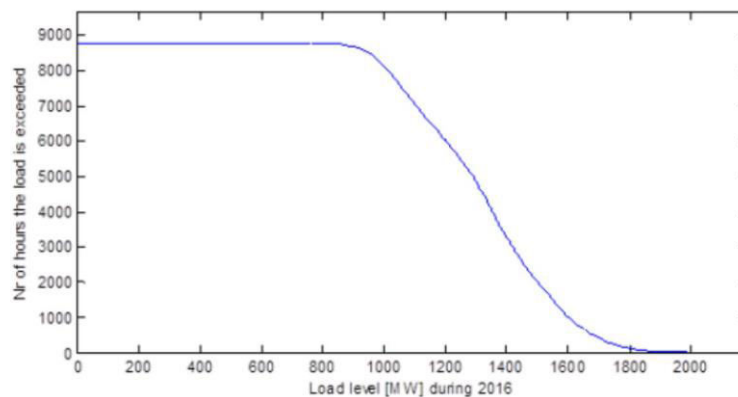
The load data in Figure 11 can now be sorted in decreasing order. One then gets the Load Duration Curve (type 1). This is shown in Figure 12.

Figure 12: Load duration curve (type 1) for load during 2016



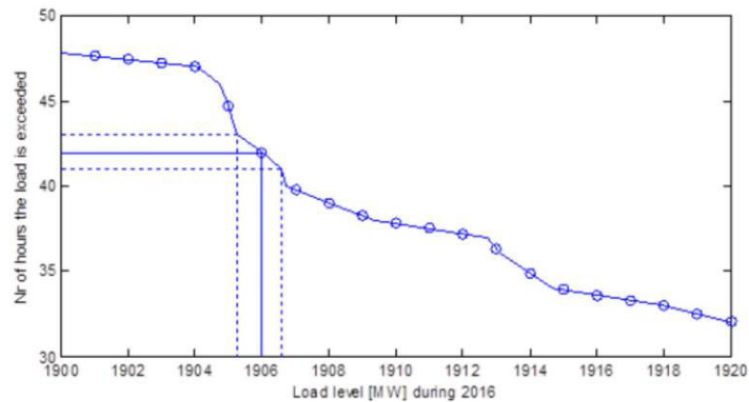
The next step in the evaluation is to interchange axis for the load duration curve in Figure 12. The result is shown in Figure 13.

Figure 13: Load duration curve for load during 2016



When one wants to make calculations one cannot directly use the data vectors used in Figure 13, since they are evenly distributed along the y-axis and not along the x-axis. We need to have one value on the y-axis for each MW-step on the x-axis. This is illustrated in Figure 14. The figure shows how the hour value (= 41.96h) for the level 1906 MW is obtained with linear interpolation between the two points (1906.57 MW, 41h) and (1905.26 MW, 43h). The interpretation is that the load level 1906 MW is exceeded during 41.96 hours.

Figure 14: Interpolation to get values on y-axis for each MW on the x-axis



3.4.1 Calculation of energy production and Loss of Load probability with thermal and hydro power plants

The power plants are tabulated in Table 5.

Table 5: Thermal and hydro power plants

Power plant	MW	Availability [%]	Merit order
Salto-Grande-base	70	99.5	1
Biomass	230	70	2
New-CCGT	500	85	3
PTI	6*50	70	4
Motores	8*10	80	5
Quinta	80	70	6
Sexta	120	70	7
Sala B	50	45	8
CTR	2*100	70	9
Rincón del Bonete	4*38	99.5	10
Baygorria	3*36	99.5	11
Palmar	3*111	99.5	12
Salto Grande-flexible	6*146	99.5	13

The calculations will be performed using the Probabilistic Production Cost Method. This means that one performs convolution where the assumption is that outages in different power plants are independent from each other and are as common in high load as during low load.

The challenge is then to estimate the “Equivalent Load Duration Curve” which can be obtained as

$$F_k(x) = p_k F_{k-1}(x) + q_k F_{k-1}(x - G_k) \quad (1)$$

where

$F_0(x)$ = Load Duration Curve in point x, as drawn in Figure 13

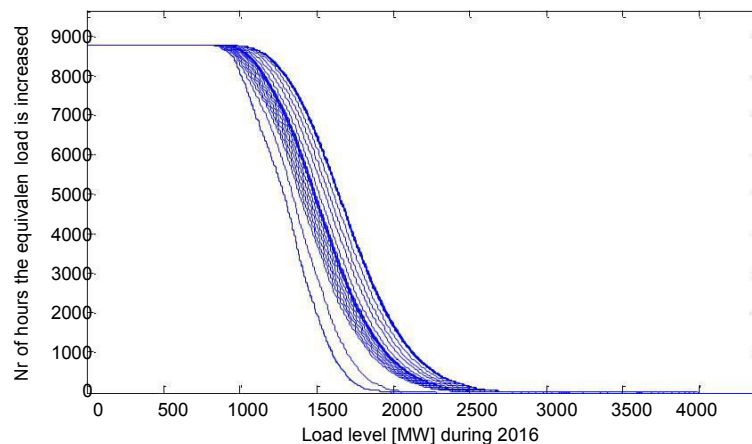
P_k = availability of power plant k, from Table 5

$Q_k = 1 - p_k$ = unavailability of power plant k

G_k = installed capacity in power plant k, from Table 5

We first assume that hydro plants are used first (base load), and then secondly that they are loaded at the end (peak shaving). All the equivalent load duration curves are shown in Figure 15.

Figure 15: Equivalent load duration curves. The one to the left is the first load duration curve, i.e. the same as in Figure 13. The next one then contains (equivalent load 1 = load + outages in unit 1) and the next (equivalent load 2 = load + outage in units 1 and 2) etc. up to the one to the right which includes (final equivalent load = load + outage in all units). The LOLP is equal to probability that (load > available capacity) = probability that (load > installed capacity – outages) = probability that (load + outages > installed capacity) = probability that (equivalent load > installed capacity). Because of this the LOLP can be read directly in the final equivalent load duration curve = the value in the point of installed capacity.



The expected energy production depends on whether the hydro power is base loaded or peak loaded. Base loaded means that the power is used all the time. Peak loaded means that hydro power is only used when the other power plants cannot meet the demand. The method used, i.e., study a whole period (here a year) means that peak loading assumes that the water can be stored to be used only in peak load situation and not used at all when other power plants can meet the load. It is also possible to have some hydro power base loaded and some power peak loaded. It is also possible to load hydro in any positions between these level, if, e.g., some thermal units are only used in peak load situations. From reliability point of view (LOLP) it does not matter in which order the hydro power is loaded, as long as

there is water enough to produce the calculated energy. The result is shown in Table 6.

Table 6: Results for energy production per source with data according to Table 5

Power plant	Hydro power base loaded [TWh]	Hydro power peak loaded [TWh]	Hydro power peak loaded -948 MW [TWh]
Salto-Grande-base	0.6118	0.6118	0.6118
Biomass	0.1264	1.414	1.414
New-CCGT	0.06124	3.733	3.733
PTI	0.009484	1.81	1.81
Motores	0.0007403	0.5176	0.5176
Quinta	0.0002915	0.4271	0.4271
Sexta	0.000193	0.5914	0.5914
Sala B	3.157e-005	0.1482	0.1482
CTR	7.767e-005	0.8021	0.8021
Rincón del Bonete	1.328	0.6523	0.6523
Baygorria	0.9439	0.321	0.321
Palmar	2.91	0.4705	0.1035
Salto Grande-flexible	5.621	0.1151	0.311
Total prod:⁴	11.61	11.61	11.44
Total hydro prod.:	11.42	2.171	2.00
LOLP [hours/year]	0.2882	0.2882	910.3

For the four hydro power plants one can see that the difference in energy production when they are base loaded (total production = 11.42 TWh), and peak loaded (total production is 2.171 TWh) is 9.25 TWh which then depends on the water availability.

If the water availability is lower than 2.171 TWh then the installed capacity cannot be used as much as needed. Peak loading of hydro power means that hydro power is only used when all the other power plants cannot meet the load. If peak loading results in too much use of hydro energy, then this corresponds to that all the capacity in hydro power cannot be used all the time (since there is not enough water). The situation can be simulated by reducing the capacity in the hydro power until the energy target is reached. We assume here that:

- › hydro power is fully controllable (i.e. no base load hydro power)
- › the available hydro energy is 2.0 TWh (just taken as an example here)

⁴ The reason why the figures are smaller than 11.618 is that there is some LOLP (= not all energy is served).

- › we decrease the capacity at some hydro power plants until the target is obtained

A way to get this is to decrease each of the six peak capacity units in Salto Grande with 110 MW => a total decrease of 660 MW, and each of the 3 hydro units in Palmar with 96 MW => a decrease of 288 MW i.e. a total capacity decrease of 948 MW. The result is shown in the right column of Table 6. The total hydro power production is now $0,6118+0,6523+0,321+0,1035+0,311=2,0$ TWh and the amount of hours with not enough capacity has increased significantly from 0,288 hours per year to 910 hours per year.

The LOLP means formally “loss of load probability”, but if one has other power plants or if the area is interconnected to other areas, then in this case this means that during 0,288 hours per year (=0.003 percent of the year) other capacity is needed, i.e. import or other units. With lower amount of water this time increases to 10.4 percent of the year. Table 6 also shows that lack of water decreases the energy production since the demand cannot always be fulfilled, in this case a decrease of $11.61-11.44 = 0.17$ TWh.

For a further explanation of the calculations with hydro power including also the peak-loading, see Appendix A.

For a description of how to handle dry year situation concerning LOLP calculation, see also Appendix B.

3.4.2 Introduction of wind power in the calculations

Wind power data from three sites are available for the years 1983-2012. The size of the wind parks are shown in Table 7. Available short term data from several sites were compared and the conclusion was that the wind regime in Uruguay is rather similar. In other words when the wind blows it blows all over Uruguay – having said that it is rather conservative to spread the 1000 MW on only three sites as it will not take full account of the smoothening effect.

Table 7: Three sites with wind power

Name	Installed amount of MW
Pintado	400
Peralta	200
Caracoles	400

Here first the wind power data for the year 2012 will be used. Figure 16 shows the production per site for one day, and Figure 17 shows the total production for the first two weeks of 2012.

Figure 16: Wind power production in the three sites during January 1, 2012

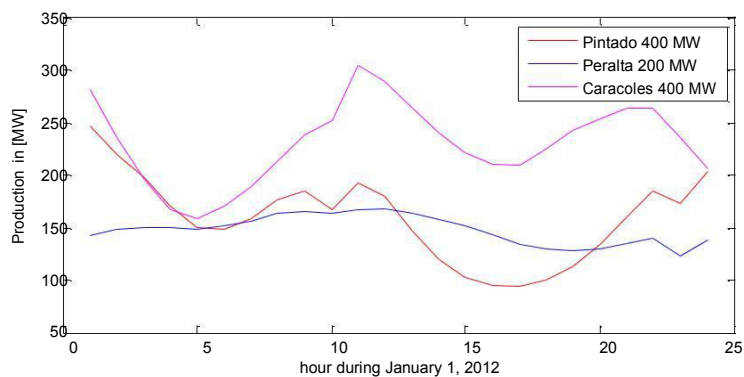
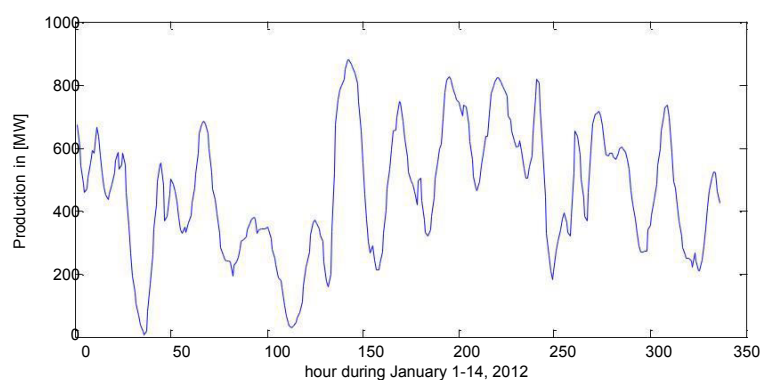
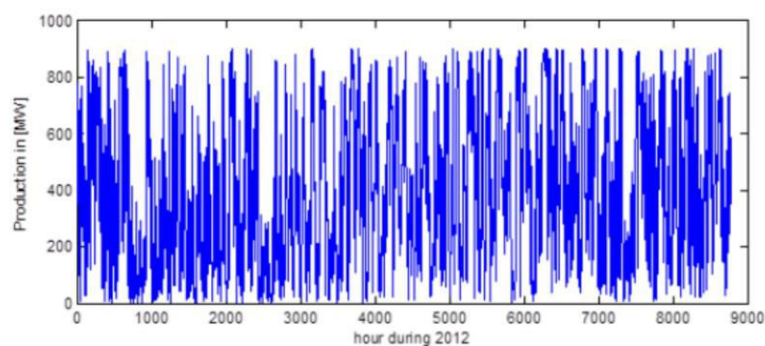


Figure 17: Total wind power production from the three sites during the first two weeks of 2012



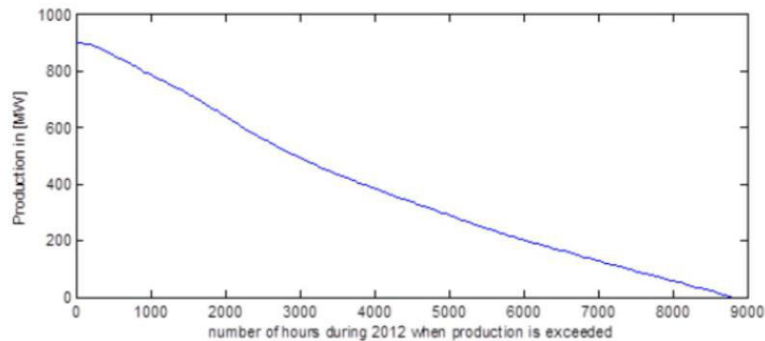
If one then takes the whole year then the production is shown in Figure 18. The yearly energy production is 3.16 TWh and the maximum production is 901.49 MW, i.e., installed capacity (1000 MW) is never obtained. The utilization time (yearly production) / (installed capacity) then becomes $3441583/1000 = 3162$ hours.

Figure 18: Total wind power production during 2012



The data in Figure 18 can be sorted and then one obtains the duration curve of the produced wind power. This curve is shown in Figure 19.

Figure 19: Wind power production duration curve for 2012

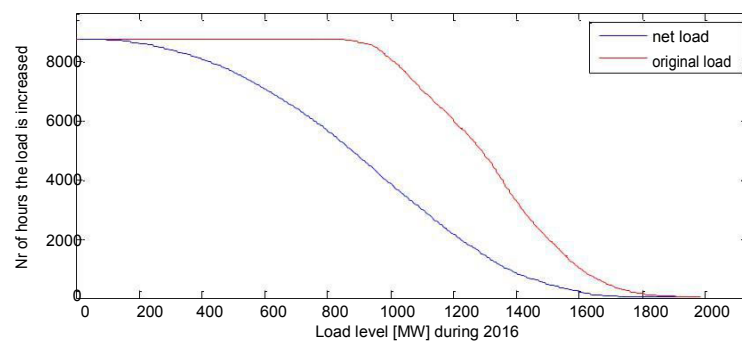


One can now perform the same calculation as above, when there was no wind power. The first step is to calculate the net demand. This is performed so one for each hour takes:

$$\text{Net load (hour } k) = \text{load (hour } k) - \text{wind power (hour } k)$$

When this is done, one can calculate the net load duration curve. This is shown in Figure 20 together with the original load duration curve from Figure 13.

Figure 20: Net load duration curve and original load duration curve (same as in Figure 13)



One can now integrate all the other power plants with the same method as shown earlier, but now use the net load duration curve. One can see it as the other power plant have to cover the rest of the load that is not covered by wind power. The result is shown in Table 8. In the table it is that the reliability of the system is improved thanks to wind power since the LOLP has decreased to 0.02399 hours/year (earlier 0.2882 hours/year).

Table 8: Energy production and system reliability with wind power in the system

Power plant	Hydro power base loaded [TWh]	Hydro power peak loaded [TWh]
Wind power	3.162	3.162
Salto-Grande-base	0.6111	0.6111
Biomass	0.02379	1.397
New-CCGT	0.01017	3.318
PTI	0.001643	1.25
Motores	9.274e-005	0.3128
Quinta	3.126e-005	0.2404
Sexta	1.833e-005	0.3073
Sala B	2.932e-006	0.07329
CTR	6.663e-006	0.3688
Rincón del Bonete	1.319	0.2695
Baygorria	0.9207	0.12
Palmar	2.615	0.1557
Salto Grande-flexible	2.952	0.02895
Total prod:	3.162+8.453=11.61	3.162+8.453=11.61
Total hydro prod.:	8.418	1.185
LOLP [hours/year]	0.02399	0.02399

The “capacity credit” can now be estimated with the three different methods:

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2882 hours per year as stated in Table 6. If one now take the system with wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 153.3 MW then the LOLP becomes 0.2885 hours/year (instead of 0.024). This means **that the ELCC capacity credit of 1000 MW of wind power is 153.3 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 135.0 MW then the LOLP becomes 0.0231 hours per year. This means **that the EFC capacity credit of 1000 MW of wind power is 135 MW.** This is not exactly the same as the ELCC. The reason is that one makes the comparison at different Equivalent Load Duration Curves (ELDC). For ELCC one studies the ELDC **with** wind power, while one for the EFC-method studies the ELDC **without** wind power.

Equivalent Conventional Capacity - ECC

This means that one studies how large a conventional power plant must be in order to decrease the LOLP as much as the wind power decreased it. Here we assume that the conventional power plant has an availability of 80 percent, i.e. the same as

the new CCGT plant. If one then take the base system and adds one 80 percent available power station with capacity 1000 MW then the LOLP becomes 0.0576 hours per year. This means that it is not possible, no matter the size of the unit to have one unit with 80 percent availability that decreases the LOLP to the required level 0.024 hours per year. Since there is not extra capacity during 20 percent of the time (with an assumption of 80 percent availability), then it is only possible to decrease the LOLP to $0.2 \cdot 0.2882 = 0.0576$ hours/year. We now instead use three extra power plants of equal size and availability 80 percent. If the size of each of these three plants is 66 MW, then the LOLP becomes 0.0235. This means **that the ECC capacity credit of 1000 MW of wind power is infinite MW if one plant is used and $3 \cdot 66 = 198$ MW if three plants are used.**

3.4.3 Calculations

In the previous section we have used an assumed merit order. However the merit order of the thermal power stations has no impact on the risk of capacity credit. But in order to have a realistic view also concerning the energy production in different units it is important to consider the merit order so the results show that units with low operation cost will be used as much as possible. It is also important to consider that some hydro power is of run-of-the-river type so it has to be used all the time. From now the following merit order will be used, see Table 9. It can be noted that one part of Salto-Grande [70 MW] is of “run-of-the-river” type, i.e. it is used all the time, while another part [875 MW] is flexible and can be used, e.g., only in peak situations. All other hydro is also classified as “flexible”, i.e. it is assumed that there is storage enough to store water from low-need situations to high-need situations.

Table 9: Merit order used in the calculations

Power plant	Merit order	MW	Availability [%]	Operation cost
Salto-Grande-base	1	70	99.5	-
Biomass	2	230	70	115
New-CCGT	3	500	85	135
PTI	4	6*50	70	1 60
Motores	5	8*1 0	80	1 65,5
Quinta	6	80	70	1 87,8
Sexta	7	1 20	70	1 90
Sala B	8	50	45	231,5
CTR	9	2*100	70	278,3
Rincón del Bonete	10	4*38	99.5	-
Baygorria	11	3*36	99.5	-
Palmar	12	3*1 11	99.5	-
Salto Grande-flexible	13	6*1 46	99.5	-

Depending on the demand and the distribution of the demand, different amount of energy will be produced in the different plants. With a merit order according to Table 9 there will often be comparatively low energy production in the last units,

i.e. the hydro units. But as long as this energy level is lower than the available hydro energy then the risk of capacity credit is correct. If one wants to have a correct expected energy production (which is not requested here) then one has to use the extra available water to offload the most expensive thermal power plants (i.e. exchange merit order of them) until the correct hydro energy production is obtained. But this “merit order exchange” will **not** affect the LOLP, i.e. it will not affect the capacity credits.

We will now calculate the energy production and LOLP for several years including also dry years in order to estimate the capacity credit for wind power. The calculations are performed in the following way. We here assume that we study hydrological and wind year X. However the load data from 2012 (scaled to 2016) is always used:

- › Use the yearly demand curve for 2012 and scale it up to 2016. The load from 2012 to 2016 is assumed to increase with 3.7% per year, i.e. multiply the load during each hour with 1.037^4 .
- › Divide the year into four periods per-1: Summer-Jan-Mar, per-2: Autumn-Apr-Jun, per-3: Winter-Jul-Sep, per-4: Spring-Oct-Dec. Calculate the LOLP (hours/year) for each period with the method shown above, and power stations and merit order according to Table 9. In this calculation one considers the possible energy limitation for each period for year X. If the available hydro energy is lower than the obtained hydro energy with the hydro power plants peak loaded with data as in Table 9, then the capacities of the hydro stations have to be decreased. The method is to decrease the last unit first following with the second last etc., until there is a correspondence between available hydro energy for each period in year X and obtained hydro energy for each period.
- › The result is one LOLP per period: LOLP-1, LOLP-2, LOLP-3, LOLP-4.
- › The total LOLP (h/year) is the sum of the LOLP for each period.
- › Then add wind power from year X and make the LOLP calculations in the same way as under point 2 above.
- › The result is one LOLP per period: LOLP-W1, LOLP-W2, LOLP-W3, LOLP-W4.
- › The total LOLP (h/year) is the sum of the LOLP for each period.
- › The capacity credit for wind power for year X is then calculated in the same way as shown above for the three methods: ELCC, EFC and ECC

It can be noted that the method is based on that it is not possible to move available water between the different periods. There may be, e.g., a surplus of water in one period but not in the next. However this possibility is not considered here.

Three years will be studied: 2006 (dry), 1993 (average) and 1984 (wet). We will also study three different wind power levels: 800 MW, 1000 MW and 1200 MW. The presented wind data above are for 1000 MW, so we will only linearly scale these data to get 800 MW or 1200 MW. For each case we will then calculate the capacity credit for wind power with the three methods: ELCC, EFC and ECC

Results for 2006 (dry year)

Load data are taken from 2012 and scaled up to 2016. Available hydro energy per period is provided and shown in Table 10. Wind data and hydro availability are taken from 2006. The yearly wind energy production with 1000 MW is 3.01 TWh. With 800 MW it becomes 2.41 TWh while it with 1200 MW becomes 3.62 TWh.

The first step is to calculate the LOLP for the four periods and no wind power. The result is shown in Table 10.

Table 10: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 2006. No wind power.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Salto-Grande-base	0.1504	0.1521	0.1538	0.1538	0.6101
Biomass	0.3478	0.3516	0.3555	0.3555	1.4104
New-CCGT	0.9180	0.9282	0.9384	0.9384	3. 7230
PTI	0.4484	0.4456	0.4580	0.4533	1. 8052
Motores	0.1305	0.1247	0.1329	0.1280	0.5162
Quinta	0.1085	0.1020	0.1106	0.1049	0.4260
Sexta	0.1497	0.1408	0.1552	0.1441	0.5898
Sala B	0.0374	0.0351	0.0395	0.0358	0. 1478
CTR	0.2014	0.1882	0.2213	0.1892	0. 8001
Rincón del Bonete	0.1616	0.1511	0.1923	0.1460	0. 6509
Baygorria	0.0776	0.0733	0.1023	0.0673	0.3205
Palmar	0.1091	0.1054	0.1642	0.0912	0.4700
Salto Grande-flexible	0.0242	0.0247	0.0479	0.0183	0.1151
Total production: TWh	2.8647	2.8227	3.0719	2.8257	11. 5850
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.5230	0.5065	0.6605	0.4765	2. 1666
Available hydro: TWh	0.8614	0.7345	1.0339	1.1708	3.8006
LOLP: hours	0.0077	0.0383	0.2431	0.0019	0.2910

In the calculations, Salto-Grande is divided in "base" and "flexible". In some periods Salto Grande-flexible is not operating at its full capacity in the calculations because there is no need from a supply point of view, but probably there is from an economic dispatch point of view.

In Table 10 it is shown that in the dry year there is still enough water to cover the needs for hydro power when it is peak loaded, i.e. hydro (except for base loaded 70 MW of Salto-Grande) is only used when there is not enough capacity to cover the load in the available thermal power plants.

2006: 1000 MW of wind power

Now the same calculations are performed with 1000 MW of wind power from 2006. The results are shown in Table 11.

Table 11: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 2006. Wind power data for 1000 MW for 2006.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.6439	0.7354	0.8415	0.7925	3.0133
Salto-Grande-base	0.1504	0.1521	0.1538	0.1537	0.6100
Biomass	0.3465	0.3480	0.3544	0.3528	1.4016
New-CCGT	0.8733	0.8402	0.8556	0.8347	3.4039
PTI	0.3481	0.3137	0.3321	0.3022	1.2962
Motores	0.0877	0.0774	0.0848	0.0739	0.3238
Quinta	0.0668	0.0587	0.0659	0.0550	0.2463
Sexta	0.0840	0.0735	0.0854	0.0678	0.3107
Sala B	0.0199	0.0173	0.0206	0.0158	0.0736
CTR	0.0988	0.0850	0.1053	0.0761	0.3652
Rincón del Bonete	0.0706	0.0597	0.0789	0.0517	0.2609
Baygorria	0.0307	0.0255	0.0360	0.0214	0.1136
Palmar	0.0382	0.0315	0.0482	0.0252	0.1430
Salto Grande-flexible	0.0062	0.0049	0.0097	0.0032	0.0239
Total production: TWh	2.8650	2.8229	3.0722	2.8260	11.5861
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.2961	0.2737	0.3265	0.2552	1.1515
Available hydro: TWh	0.8614	0.7345	1.0339	1.1708	3.8006
LOLP: hours	0.0014	0.0008	0.0071	0.0000	0.0093

Table 11 now shows that thanks to wind power the LOLP decreases during all periods. It is now even lower than without wind power. It has decreased from 0.2910 hours in Table 10 to 0.0093 hours in Table 11.

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 10. If one now takes the system with wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 193.3 MW then the LOLP becomes 0.2908 hours/year (instead of 0.0093 hours). This means **that the ELCC capacity credit of 1000 MW of wind power for 2006 is 193.3 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 177 MW then the LOLP becomes 0.0093 hours per year. This means **that the EFC capacity credit of 1000 MW of wind power is 177 MW.**

Equivalent Conventional Capacity - ECC

This means that one studies how large a conventional power plant must be in order to decrease the LOLP as much as the wind power decreased it. Here we assume that there is one single conventional power plant that has an availability of 80 percent, i.e. the same as the new CCGT plant. However, there is a challenge with this definition for this case. Without wind power the LOLP is 0.2910 hours/year. Assume that a new plant is available during 80 percent of the time. This this plant is not available during 20 percent of the time so the plant will not reduce the capacity deficit during at least 20 percent of 0.2910 hours. So the LOLP will still be at least $0.20 \cdot 0.2910 = 0.0582$ hours. So no matter the size of the 80 percent available unit, the LOLP cannot be decreased to a level lower than 0.0582 hours. But the LOLP with 1000 MW wind power is 0.0093! This means that the capacity credit of wind power is higher than any size of a single thermal power plant with 80 percent availability. The method used here is instead to use three (=3) power stations with an availability of 80 percent. The ECC is then calculated as the sum of these three units. When the capacity of each of the three units (with availability 80 percent) is 100 MW (i.e. a total of 300 MW), then the LOLP is 0.0092 hours per year. This means **that the ECC capacity credit of 1000 MW of wind power is 300 MW.**

2006: 800 MW of wind power

Now the same calculations are performed with 800 MW of wind power from 2006. The results are shown in Table 12.

Table 12: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 2006. Wind power data for 800 MW for 2006.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.5151	0.5883	0.6732	0.6340	2.4106
Salto-Grande-base	0.1504	0.1521	0.1538	0.1538	0.6101
Biomass	0.3477	0.3512	0.3555	0.3551	1.4095
New-CCGT	0.8966	0.8793	0.8973	0.8829	3.5561
PTI	0.3776	0.3457	0.3653	0.3379	1.4266
Motores	0.0977	0.0873	0.0956	0.0846	0.3652
Quinta	0.0755	0.0670	0.0753	0.0643	0.2822
Sexta	0.0962	0.0849	0.0987	0.0799	0.3597
Sala B	0.0228	0.0201	0.0240	0.0187	0.0856
CTR	0.1141	0.0999	0.1238	0.0909	0.4287
Rincón del Bonete	0.0822	0.0711	0.0941	0.0624	0.3098
Baygorria	0.0360	0.0308	0.0436	0.0261	0.1365
Palmar	0.0456	0.0387	0.0594	0.0313	0.1750
Salto Grande-flexible	0.0075	0.0063	0.0124	0.0041	0.0303
Total production: TWh	2.8649	2.8229	3.0721	2.8259	11.5859
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.3217	0.2991	0.3633	0.2777	1.2617
Available hydro: TWh	0.8614	0.7345	1.0339	1.1708	3.8006
LOLP: hours	0.0016	0.0013	0.0114	0.0001	0.01444

Table 12 now shows that thanks to 800 MW of wind power the LOLP decreases. . Comparing Table 10 with Table 12 shows that thanks to wind power the LOLP decreases from 0.2910 hours to 0.0144 hours, i.e. slightly higher LOLP compared to 1000 MW of wind power.

Equivalent Load Carrying Capacity - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 10. If one now takes the system with 800 MW wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 170.2 MW then the LOLP becomes 0.2911 hours/year (instead of 0.0144 hours). This means **that the ELCC capacity credit of 800 MW of wind power for 2006 is 170.2 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 157.5 MW then the LOLP becomes 0.0144 hours per year. This means **that the EFC capacity credit of 800 MW of wind power is 157.5 MW.**

Equivalent Conventional Capacity - ECC

This means that one studies how large a conventional power plant must be in order to decrease the LOLP as much as the wind power decreased it. Here we assume that the conventional power plant has an availability of 80 percent, i.e. the same as the new CCGT plant. It is not, as described above, possible to use only one plant. So here, as above, three power plants which each has an availability of 80 percent is used. With a size of each plant of 83 MW then the LOLP becomes 0.0142 hours. This means **that the ECC capacity credit of 800 MW of wind power is $3 \times 83 = 249$ MW.**

2006: 1200 MW of wind power

Now the same calculations are performed with 1200 MW of wind power from 2006. The results are shown in Table 13.

Table 13: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 2006. Wind power data for 1200 MW for 2006.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.7726	0.8825	1.0098	0.9510	3.6159
Salto-Grande-base	0.1498	0.1507	0.1535	0.1529	0.6069
Biomass	0.3440	0.3415	0.3476	0.3464	1.3795
New-CCGT	0.8403	0.7923	0.8028	0.7750	3.2103
PTI	0.3181	0.2832	0.2989	0.2697	1.1699
Motores	0.0783	0.0686	0.0749	0.0641	0.2859
Quinta	0.0590	0.0515	0.0578	0.0473	0.2156
Sexta	0.0739	0.0639	0.0742	0.0580	0.2700
Sala B	0.0174	0.0150	0.0178	0.0135	0.0636
CTR	0.0863	0.0729	0.0903	0.0646	0.3141

Rincón del Bonete	0.0613	0.0507	0.0669	0.0436	0.2224
Baygorria	0.0264	0.0215	0.0302	0.0178	0.0960
Palmar	0.0326	0.0260	0.0398	0.0207	0.1191
Salto Grande-flexible	0.0052	0.0039	0.0078	0.0025	0.0195
Total production: TWh	2.8652	2.8241	3.0723	2.8271	11.588
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.2754	0.2527	0.2982	0.2375	1.0638
Available hydro: TWh	0.8614	0.7345	1.0339	1.1708	3.8006
LOLP: hours	0.0011	0.0005	0.0046	0.0000	0.0062

Table 13 now shows that thanks to 1200 MW of wind power the LOLP decreases. Comparing Table 10 with Table 13 shows that thanks to wind power the LOLP decreases from 0.2910 hours to 0.0062 hours, i.e. slightly lower LOLP compared to 1000 MW of wind power.

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 10. If one now takes the system with 1200 MW wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 214.1 MW then the LOLP becomes 0.2908 hours/year (instead of 0.2910 hours). This means **that the ELCC capacity credit of 1200 MW of wind power for 2006 is 214.1 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 194.2 MW then the LOLP becomes 0.0062 hours per year. This means **that the EFC capacity credit of 1200 MW of wind power is 194.2 MW**

Equivalent Conventional Capacity - ECC

This means that one studies how large a conventional power plant must be in order to decrease the LOLP as much as the wind power decreased it. Here we assume, as described above, that there are three conventional power plant which each has an availability of 80 percent, i.e. the same as the new CCGT plant. If one then takes the base system and adds three 80 percent available power station with capacity 120 MW each then the LOLP becomes 0.0062 hours per year. This means **that the ECC capacity credit of 1200 MW of wind power is 360 MW.**

A summary of the capacity credit of wind power is shown in Table 14.

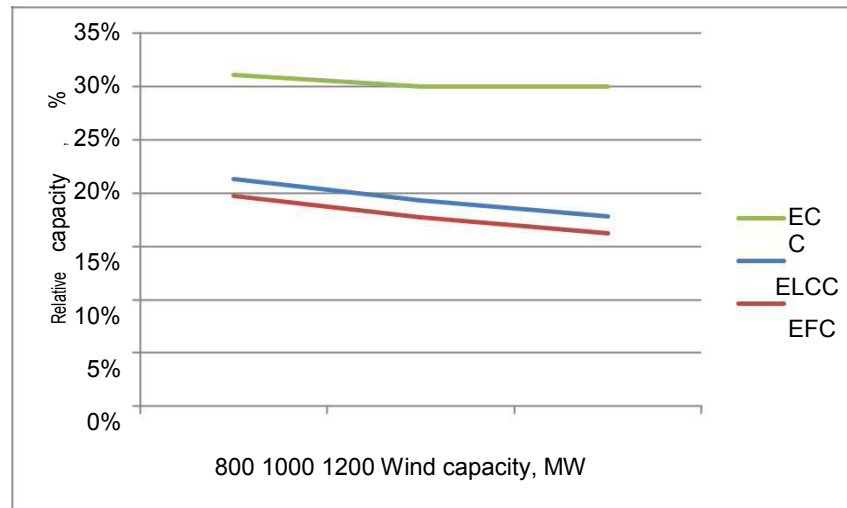
Table 14: Summary of results of wind power capacity credits for 2006 – dry year

Wind cap.	800 MW			1000 MW			1200 MW		
	MW	% of 800	% of Ym	MW	% of 1000	% of Ym	MW	% of 1200	% of Ym
ELCC	170.2	21.3	61.9	193.3	19.3	56.2	214.1	17.8	51.9
EFC	157.5	19.7	57.2	177	17.7	51.5	194.2	16.2	47.0
ECC	249	31.1	90.5	300	30.0	87.2	360	30.0	87.2
Yearly mean	275.18	34.4	-	343.98	34.4	-	412.77	34.4	-

Table 14 also shows the capacity credits in relation to yearly mean (Ym) power production. This value is of certain interest when one compares different energy sources with each other. For wind power one needs more capacity for the same amount of energy compared to a base load unit. Concerning the “% of Ym” for “ECC” the value is calculated as $0.80 \cdot (\text{ECC in MW}) / (\text{Ym in MW})$ since the assumption here is to compare the wind power with three base loaded units with 80% availability.

The general conclusion is that the relative capacity credit decreases slightly with larger amounts of wind power (see also Figure 21 below). Furthermore, it appears that the ECC method (80 % availability) gives the highest capacity credit whereas the EFC method (100 % availability) gives the lowest capacity credit.

Figure 21: Summary of results of wind power capacity credits for 2006 – dry year



Results for 1993 (average hydrological year)

Load data are taken from 2012 and scaled up to 2016. Available hydro energy per period is provided and shown in Table 15. Wind data and hydro availability are taken from 1993. The yearly wind energy production with 1000 MW is 3.23 TWh. With 800 MW it becomes 2.58 TWh while it with 1200 MW becomes 3.87 TWh.

The first step is to calculate the LOLP for the four periods and no wind power. The result is shown in Table 15.

Table 15: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 1993. No wind power.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Salto-Grande-base	0.1504	0.1521	0.1538	0.1538	0.6101
Biomass	0.3478	0.3516	0.3555	0.3555	1.4104
New-CCGT	0.9180	0.9282	0.9384	0.9384	3.7230
PTI	0.4484	0.4456	0.4580	0.4533	1.8052
Motores	0.1305	0.1247	0.1329	0.1280	0.5162
Quinta	0.1085	0.1020	0.1106	0.1049	0.4260
Sexta	0.1497	0.1408	0.1552	0.1441	0.5898
Sala B	0.0374	0.0351	0.0395	0.0358	0.1478
CTR	0.2014	0.1882	0.2213	0.1892	0.8001
Rincón del Bonete	0.1616	0.1511	0.1923	0.1460	0.6509
Baygorria	0.0776	0.0733	0.1023	0.0673	0.3205
Palmar	0.1091	0.1054	0.1642	0.0912	0.4700
Salto Grande-flexible	0.0242	0.0247	0.0479	0.0183	0.1151
Total production: TWh	2.8647	2.8227	3.0719	2.8257	11.5850
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.5230	0.5065	0.6605	0.4765	2.1666
Available hydro: TWh	1.7946	2.1479	1.9167	2.1492	8.0084
LOLP: hours	0.0077	0.0383	0.2431	0.0019	0.2910

In Table 15 it is shown that there is no lack of water in any of the periods. One can also see that with the here assumed data of load and generation resources there will not be any extra need of decreasing the hydro capacity as long as the available water in TWh is larger than 0.5230 (period 1), 0.5065 (period 2), 0.6605 (period 3), and 0.4765 (period 4). As stated above the here calculated energy production per source is based on peak loaded flexible hydro. But with higher amount of water available, then this extra water can be used to offload the most expensive thermal power. However, this will not affect the LOLP which is the main variable used to calculate the capacity credit.

1993: 1000 MW of wind power

Now the same calculations are performed with 1000 MW of wind power from 1993. The results are shown in Table 16.

Table 16: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 1993. Wind power data for 1000 MW for 1993

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.6567	0.8291	0.8462	0.8963	3.2283
Salto-Grande-base	0.1504	0.1521	0.1538	0.1535	0.6098
Biomass	0.3459	0.3457	0.3528	0.3499	1.3942
New-CCGT	0.8661	0.7998	0.8409	0.8020	3.3088
PTI	0.3434	0.2895	0.3285	0.2763	1.2378
Motores	0.0871	0.0713	0.0842	0.0660	0.3086
Quinta	0.0670	0.0540	0.0656	0.0495	0.2361
Sexta	0.0851	0.0680	0.0854	0.0610	0.2995
Sala B	0.0202	0.0161	0.0207	0.0142	0.0711
CTR	0.0997	0.0797	0.1070	0.0679	0.3543
Rincón del Bonete	0.0702	0.0567	0.0822	0.0458	0.2550
Baygorria	0.0301	0.0246	0.0388	0.0188	0.1122
Palmar	0.0374	0.0311	0.0541	0.0220	0.1446
Salto Grande-flexible	0.0057	0.0054	0.0122	0.0028	0.0261
Total production: TWh	2.8650	2.8230	3.0723	2.8261	11.5864
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.2938	0.2698	0.3410	0.2429	1.1476
Available hydro: TWh	1.7946	2.1479	1.9167	2.1492	8.0084
LOLP: hours	0.0006	0.0073	0.0339	0.0000	0.0418

Table 16 now shows that thanks to wind power the LOLP has decreased. Comparing Table 15 with Table 16 shows that the LOLP decreases from 0.2910 hours to 0.0418 hours. The levels are comparatively low and the decrease is then also low.

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 15. If one now takes the system with wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 133.0 MW then the LOLP becomes 0.2909 hours/year (instead of 0.0418 hours). This means **that the ELCC capacity credit of 1000 MW of wind power for 1993 is 133 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 107 MW then the LOLP becomes 0.0419 hours per year. This means **that the EFC capacity credit of 1000 MW of wind power is 107 MW**

Equivalent Conventional Capacity - ECC

This means that one studies how large a conventional power plant must be in order to decrease the LOLP as much as the wind power decreased it. Here we assume that the conventional power plant has an availability of 80 percent, i.e. the same as

the new CCGT plant. If one then takes the base system and adds a 80 percent available power station with e.g. capacity 400 MW then the LOLP becomes 0.0582 hours per year. Even if the unit becomes 1000 MW it is not possible to decrease the LOLP below 0.0582 hours/year. Assume that a new unit takes away all lack of capacity during 80 percent of the time. Then the LOLP decreases from 0.2909 hours/year down to $0.2 \cdot 0.2909 = 0.0582$ hours. This means that a single conventional unit that should decrease the LOLP as much as the wind power must have an availability which is higher than $(1 - 0.0418 / 0.2909) = 85.63$ percent or be divided into several units. With an assumed availability of 80 percent the ECC cannot be defined. As above the strategy is then to instead calculate the ECC as the total capacity of three units which each has an availability of 80 percent. If one then take away the wind power and instead install three units of 50 MW each with 80 percent availability, then the LOLP becomes 0.0413 hours/year. This means **that the ECC capacity credit of 1000 MW of wind power is 150 MW**

1993: 800 MW of wind power

Now the same calculations are performed with 800 MW of wind power from 1993. The results are shown in Table 17.

Table 17: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 1993. Wind power data for 800 MW for 1993.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.5254	0.6633	0.6769	0.7171	2.5827
Salto-Grande-base	0.1504	0.1521	0.1538	0.1538	0.6101
Biomass	0.3477	0.3513	0.3553	0.3549	1.4092
New-CCGT	0.8939	0.8537	0.8880	0.8654	3.5010
PTI	0.3737	0.3257	0.3618	0.3186	1.3797
Motores	0.0967	0.0818	0.0951	0.0773	0.3509
Quinta	0.0750	0.0625	0.0748	0.0584	0.2708
Sexta	0.0962	0.0792	0.0982	0.0726	0.3462
Sala B	0.0229	0.0188	0.0239	0.0169	0.0825
CTR	0.1145	0.0938	0.1240	0.0817	0.4140
Rincón del Bonete	0.0817	0.0673	0.0960	0.0556	0.3006
Baygorria	0.0353	0.0294	0.0456	0.0230	0.1334
Palmar	0.0445	0.0375	0.0642	0.0272	0.1733
Salto Grande-flexible	0.0070	0.0065	0.0146	0.0035	0.0317
Total production: TWh	2.8649	2.8230	3.0722	2.8259	11.5861
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.3189	0.2928	0.3742	0.2632	1.2491
Available hydro: TWh	1.7946	2.1479	1.9167	2.149292	8.0084
LOLP: hours	0.0008	0.0078	0.0395	0.0001	0.048148

Table 17 now shows that thanks to 800 MW of wind power the LOLP decreases. Comparing Table 15 with Table 17 shows that the LOLP decreases from 0.2910 hours to 0.0481 hours, i.e. slightly higher LOLP compared to 1000 MW of wind power.

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 15. If one now takes the system with 800 MW wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 121.6 MW then the LOLP becomes 0.2911 hours/year (instead of 0.0481 hours). This means **that the ELCC capacity credit of 800 MW of wind power for 1993 is 121.6 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 100 MW then the LOLP becomes 0.0479 hours per year. This means **that the EFC capacity credit of 800 MW of wind power is 100 MW**

Equivalent Conventional Capacity - ECC

This means that one studies how large a conventional power plant must be in order to decrease the LOLP as much as the wind power decreased it. Here we assume that the conventional power plant has an availability of 80 percent, i.e. the same as the new CCGT plant. As described above we here use three units with 80 percent availability. With three 46 MW units then LOLP becomes 0.0479 hours/year. This means **that the ECC capacity credit of 800 MW of wind power is $3 \times 46 = 138$ MW**

1993: 1200 MW of wind power

Now the same calculations are performed with 1200 MW of wind power from 1993. The results are shown in Table 18.

Table 18: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 1993. Wind power data for 1200 MW for 1993.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.7881	0.9950	1.0154	1.0756	3.8740
Salto-Grande-base	0.1495	0.1499	0.1528	0.1515	0.6036
Biomass	0.3429	0.3319	0.3426	0.3369	1.3543
New-CCGT	0.8265	0.7389	0.7849	0.7264	3.0767
PTI	0.3147	0.2571	0.2953	0.2411	1.1082
Motores	0.0788	0.0626	0.0747	0.0570	0.2731
Quinta	0.0600	0.0471	0.0579	0.0425	0.2076
Sexta	0.0756	0.0590	0.0753	0.0520	0.2619
Sala B	0.0178	0.0139	0.0182	0.0120	0.0620
CTR	0.0875	0.0686	0.0937	0.0576	0.3075
Rincón del Bonete	0.0612	0.0486	0.0715	0.0386	0.2199
Baygorria	0.0260	0.0210	0.0335	0.0158	0.0963
Palmar	0.0319	0.0265	0.0466	0.0184	0.1234
Salto Grande-flexible	0.0047	0.0046	0.0105	0.0023	0.0221
Total production: TWh	2.8654	2.8245	3.0729	2.8277	11.590
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.2733	0.2505	0.3149	0.2266	1.0653
Available hydro: TWh	1.7946	2.1479	1.9167	2.1492	8.0084
LOLP: hours	0.0005	0.0069	0.0290	0.0000	0.0364

Table 18 now shows that thanks to 1200 MW of wind power LOLP decreases. Comparing Table 18 with Table 15 shows that the LOLP decreases from 0.2910 hours to 0.0364 hours, i.e. slightly lower LOLP compared to 1000 MW of wind power.

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 15. If one now takes the system with 1200 MW wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 142.6 MW then the LOLP becomes 0.2909 hours/year (instead of 0.0364 hours). This means **that the ELCC capacity credit of 1200 MW of wind power for 1993 is 142.6 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 113.6 MW then the LOLP becomes 0.0364 hours per year. This means **that the EFC capacity credit of 1200 MW of wind power is 113.6 MW**

Equivalent Conventional Capacity - ECC

This means that one studies how large a conventional power plant must be in order to decrease the LOLP as much as the wind power decreased it. Here we assume that the conventional power plant has an availability of 80 percent, i.e. the same as the new CCGT plant. As stated earlier here we use three 80 percent available units. With three 53 MW units then LOLP becomes 0.0370 hours/year. This means **that the ECC capacity credit of 1200 MW of wind power is $3 \times 53 = 159$ MW**

A summary of the capacity credit of wind power is shown in Table 19.

Table 19: Summary of result of wind power capacity credits for 1993 – average year

Wind cap.	800 MW			1000 MW			1200 MW		
	MW	% of 800	% of Ym	MW	% of 1000	% of Ym	MW	% of 1200	% of Ym
ELCC	121.6	15.2	41.2	133	13.3	36.1	142.6	11.8	32.2
EFC	100	12.5	33.9	107	10.7	29.0	113.6	9.5	25.7
ECC	138	17.3	46.8	150	15.0	40.7	159	13.25	36.0
Yearly mean	294.83	36.9	-	368.53	36.9	-	442.24	36.9	-

It can be noted that the figure for Is set to infinity since, as described above, it is not possible for any size of a single, 80 percent available unit to decrease the LOLP as much as 800, 1000 or 1200 MW of wind power. A longer description of this is found at the end of this section (page 60).

Results for 1984 (wet hydrological year)

Load data are taken from 2012 and scaled up to 2016. Available hydro energy per period is provided and shown in Table 20. Wind data and hydro availability are taken from 1984. In general it can be noted as the impact from a “wet” year is mainly that it is another year from wind point of view. A “wetter” year than an average year has in general a very small impact on the LOLP since already during an average year there is enough water to be able to use all the hydro capacity when the hydro power is peak loaded. 2012 is a long year, so data from Feb 29 is taken away. The yearly wind energy production with 1000 MW is 3.32 TWh. With 800 MW it becomes 2.65 TWh while it with 1200 MW becomes 3.98 TWh.

The first step is to calculate the LOLP for the four periods and no wind power. The result is shown in Table 20.

Table 20: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 1984. No wind power.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Salto-Grande-base	0.1504	0.1521	0.1538	0.1538	0.6101
Biomass	0.3478	0.3516	0.3555	0.3555	1.4104
New-CCGT	0.9180	0.9282	0.9384	0.9384	3.7230
PTI	0.4484	0.4456	0.4580	0.4533	1.8052
Motores	0.1305	0.1247	0.1329	0.1280	0.5162
Quinta	0.1085	0.1020	0.1106	0.1049	0.4260
Sexta	0.1497	0.1408	0.1552	0.1441	0.5898
Sala B	0.0374	0.0351	0.0395	0.0358	0.1478
CTR	0.2014	0.1882	0.2213	0.1892	0.8001
Rincón del Bonete	0.1616	0.1511	0.1923	0.1460	0.6509
Baygorria	0.0776	0.0733	0.1023	0.0673	0.3205
Palmar	0.1091	0.1054	0.1642	0.0912	0.4700
Salto Grande-flexible	0.0242	0.0247	0.0479	0.0183	0.1151
Total production: TWh	2.8647	2.8227	3.0719	2.8257	11.5850
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.5230	0.5065	0.6605	0.4765	2.1666
Available hydro: TWh	1.8887	2.5377	2.5876	2.1888	9.2028
LOLP: hours	0.0077	0.0383	0.2431	0.0019	0.2910

In Table 20 it is shown that there is no lack of water in any of the periods. This means that the result is exactly the same as in Table 15. One can also see as that with the here assumed data of load and generation resources there will not be any extra need of decreasing the hydro capacity as long as the available water in TWh is larger than 0,5230 (period 1), 0,5065 (period 2), 0,6605 (period 3), and 0,4765 (period 4). As stated above the here calculated energy production per source is based on peak loaded flexible hydro. But with higher amount of water available, then this extra water can be used to offload the most expensive thermal power. However, this will not affect the LOLP which is the main variable used to calculate the capacity credit.

1984: 1000 MW of wind power

Now the same calculations are performed with 1000 MW of wind power from 1984. The results are shown in Table 21.

Table 21: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 1984. Wind power data for 1000 MW for 1984.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.6694	0.9634	0.8899	0.7944	3.3172
Salto-Grande-base	0.1504	0.1516	0.1537	0.1538	0. 6096
Biomass	0.3467	0.3428	0.3501	0.3533	1.3929
New-CCGT	0.8560	0.7497	0.8267	0.8439	3.2763
PTI	0.3360	0.2575	0.3205	0.3004	1.2145
Motores	0.0850	0.0624	0.0824	0.0720	0. 3018
Quinta	0.0653	0.0475	0.0644	0.0539	0. 2311
Sexta	0.0834	0.0597	0.0839	0.0666	0. 2937
Sala B	0.0199	0.0141	0.0203	0.0155	0.0698
CTR	0.1005	0.0699	0.1044	0.0745	0.3494
Rincón del Bonete	0.0731	0.0498	0.0792	0.0502	0.2523
Baygorria	0.0320	0.0218	0.0367	0.0205	0. 1109
Palmar	0.0403	0.0278	0.0496	0.0239	0. 1417
Salto Grande-flexible	0.0069	0.0049	0.0104	0.0030	0. 0252
Total production: TWh	2.8649	2.8231	3.0723	2.8260	11.5863
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	0.0000
Total hydro: TWh	0.3028	0.2560	0.3296	0.2513	1.1397
Available hydro: TWh	1 .8887	2.5377	2.5876	2.1888	9. 2028
LOLP: hours	0.0004	0.0026	0.0105	0.0000	0. 0136

Table 21 now shows that thanks to wind power the LOLP has decreased. Comparing Table 20 with Table 21 shows that the LOLP decreases from 0.2910 hours to 0.0136 hours. The levels are comparatively low and the decrease is then also low.

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 20. If one now takes the system with wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 181.1 MW then the LOLP becomes 0.2911 hours/year (instead of 0.0136 hours). This means **that the ELCC capacity credit of 1000 MW of wind power for 1984 is 181.1 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 160.1 MW then the LOLP becomes 0.0136 hours per year. This means **that the EFC capacity credit of 1000 MW of wind power is 160,1 MW**

Equivalent Conventional Capacity - ECC

This means that one studies how large a conventional power plant must be in order to decrease the LOLP as much as the wind power decreased it. Here we assume that the conventional power plant has an availability of 80 percent, i.e. the same as the new CCGT plant. As above three units with 80% availability will be introduced. If three units with 85 MW capacity each and 80 percent availability are added, then the LOLP becomes 0.0134 hours/year. This means **that the ECC capacity credit of 1000 MW of wind power is $3 \cdot 85 = 255$ MW**

1984: 800 MW of wind power

Now the same calculations are performed with 800 MW of wind power from 1984. The results are shown in Table 22.

Table 22: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 1984. Wind power data for 800 MW for 1984.

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.5355	0.7707	0.7120	0.6355	2.6537
Salto-Grande-base	0.1504	0.1521	0.1538	0.1538	0.6101
Biomass	0.3478	0.3505	0.3551	0.3554	1.4087
New-CCGT	0.8883	0.8265	0.8779	0.8900	3.4826
PTI	0.3677	0.2976	0.3552	0.3411	1.3615
Motores	0.0945	0.0731	0.0928	0.0833	0.3438
Quinta	0.0732	0.0557	0.0732	0.0629	0.2650
Sexta	0.0943	0.0705	0.0964	0.0784	0.3396
Sala B	0.0226	0.0167	0.0235	0.0183	0.0811
CTR	0.1144	0.0834	0.1218	0.0886	0.4082
Rincón del Bonete	0.0838	0.0599	0.0936	0.0604	0.2977
Baygorria	0.0370	0.0263	0.0438	0.0250	0.1321
Palmar	0.0471	0.0337	0.0603	0.0295	0.1706
Salto Grande-flexible	0.0082	0.0061	0.0130	0.0037	0.0310
Total production: TWh	2.8649	2.8229	3.0722	2.8259	11.585
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.3266	0.2780	0.3645	0.2724	1.2415
Available hydro: TWh	1.8887	2.5377	2.5876	2.1888	9.2028
LOLP: hours	0.0005	0.0038	0.0147	0.0001	0.0191

Table 22 now shows that thanks to 800 MW of wind power the LOLP decreases. Comparing Table 22 with Table 20 shows that the LOLP decreases from 0.2910 hours to 0.0191 hours, i.e. slightly higher LOLP compared to 1000 MW of wind power.

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 20. If one now takes the system with 800 MW wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 160.4 MW then the

LOLP becomes 0.2912 hours/year (instead of 0.0191 hours). This means **that the ELCC capacity credit of 800 MW of wind power for 1984 is 160.4 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 144.5 MW then the LOLP becomes 0.0191 hours per year. This means **that the EFC capacity credit of 800 MW of wind power is 144.5 MW**

Equivalent Conventional Capacity - ECC

As shown above with a 80 percent available unit it is not possible to decrease the LOLP to the level 0.0191 hours per year. With three 73 MW units with 80 percent availability each, the LOLP becomes 0.0190 hours/year. This means **that the ECC capacity credit of 800 MW of wind power is $3 \times 73 = 219$ MW**

1984: 1200 MW of wind power

Now the same calculations are performed with 1200 MW of wind power from 1984. The results are shown in Table 23.

Table 23: Results with peak loaded hydro power for four periods with demand for 2016 and available hydro energy for 1984. Wind power data for 1200 MW for 1984

Power plant	Period 1 TWh	Period 2 TWh	Period 3 TWh	Period 4 TWh	Total TWh
Wind power	0.8033	1.1561	1.0679	0.9533	3.9806
Salto-Grande-base	0.1500	0.1485	0.1517	0.1530	0.6033
Biomass	0.3418	0.3236	0.3372	0.3460	1.3486
New-CCGT	0.8131	0.6669	0.7667	0.7838	3.0304
PTI	0.3068	0.2239	0.2892	0.2646	1.0845
Motores	0.0766	0.0543	0.0732	0.0627	0.2668
Quinta	0.0584	0.0410	0.0568	0.0467	0.2030
Sexta	0.0744	0.0514	0.0734	0.0574	0.2566
Sala B	0.0178	0.0121	0.0177	0.0133	0.0609
CTR	0.0893	0.0598	0.0904	0.0635	0.3030
Rincón del Bonete	0.0645	0.0424	0.0680	0.0424	0.2174
Baygorria	0.0281	0.0185	0.0312	0.0172	0.0950
Palmar	0.0352	0.0236	0.0417	0.0200	0.1204
Salto Grande-flexible	0.0060	0.0041	0.0085	0.0024	0.0210
Total production: TWh	2.8650	2.8263	3.0737	2.8264	11.5915
Hydro cap decrease [GW]	0.0000	0.0000	0.0000	0.0000	-
Total hydro: TWh	0.2837	0.2371	0.3012	0.2351	1.0571
Available hydro: TWh	1.8887	2.5377	2.5876	2.1888	9.2028
LOLP: hours	0.0002	0.0019	0.0080	0.0000	0.0101

Table 23 now shows that thanks to 1200 MW of wind power LOLP decreases. Comparing Table 23 with Table 20 shows that the LOLP decreases from 0.2910

hours to 0.0101 hours, i.e. slightly lower LOLP compared to 1000 MW of wind power.

Equivalent Load Carrying Capability - ELCC

This means that one can allow a higher load if one accepts the earlier level of LOLP, i.e. 0.2910 hours per year as stated in Table 20. If one now takes the system with 1200 MW wind power and increases the load during each hour, then the LOLP will increase. If one increases the load during each hour with 199.3 MW then the LOLP becomes 0.2903 hours/year (instead of 0.0101 hours). This means **that the ELCC capacity credit of 1200 MW of wind power for 1984 is 199.3 MW.**

Equivalent Firm Capacity - EFC

This means that one studies how large a firm power plant must be in order to decrease the LOLP as much as the wind power decreased it. If one then takes the base system (no wind power) and adds a 100 percent available power station with capacity 173.3 MW then the LOLP becomes 0.0101 hours per year. This means **that the EFC capacity credit of 1200 MW of wind power is 173.3 MW**

Equivalent Conventional Capacity - ECC

As shown above with a 80 percent available unit it is not possible to decrease the LOLP to the level 0.0101 hours per year. With three 96 MW units with 80 percent availability each, the LOLP becomes 0.0102 hours/year. This means **that the ECC capacity credit of 1200 MW of wind power is $3 \times 96 = 288$ MW.**

A summary of the capacity credit of wind power is shown in Table 24.

Table 24: Summary of result of wind power capacity credits for 1984 – wet year. Data for ECC for 1200 MW not included see above for explanation.

Wind cap.	800 MW			1000 MW			1200 MW		
	MW	% of 800	% of Ym	MW	% of 1000	% of Ym	MW	% of 1200	% of Ym
ELCC	160.4	20.1	52.9	181.1	18.1	47.8	199.3	16.6	43.9
EFC	144.5	18.1	47.7	160.1	16.0	42.3	173.3	14.4	38.1
ECC	219	27.4	72.3	255	25.5	67.3	288	24.0	63.4
Yearly Mean	302.93	37.9	-	378.68	37.9	-	454.41	37.9	-

3.4.4 Overview of all calculations

The two tables below give an overview of all the capacity credit calculations. Table 25 shows the capacity credit result in percent of the total installed amount of wind power. The figures in this table are the same figures as also earlier presented in Table 14, Table 19 and Table 24.

Table 25: Overview of capacity credit results in % of total installed amount of wind power

	800 MW	1000 MW	1200 MW
2016 – No water limitation			
- ELCC	-	15.3	-
- EFC	-	13.5	-
- ECC (1 unit)	-	∞	-
- ECC (3 units)	-	19.8	-
2016 – Dry hydrological year (2006 hydro and wind data)			
- ELCC	21.3	19.3	17.8
- EFC	19.7	17.7	16.2
- ECC (1 unit)	∞	∞	∞
- ECC (3 units)	31.1	30.0	30.0
2016 – Average hydrological year (1993 hydro and wind data)			
- ELCC	15.2	13.3	11.8
- EFC	12.5	10.7	9.5
- ECC (1 unit)	∞	∞	∞
- ECC (3 units)	17.3	15.0	13.3
2016 – Wet hydrological year (1984 hydro and wind data)			
- ELCC	20.1	18.1	16.6
- EFC	18.1	16.0	14.4
- ECC (1 unit)	∞	∞	∞
- ECC (3 units)	27.4	25.5	24.0

Since there is enough water in all years, and thereby in practice no hydro capacity decrease, the only difference between the years is the wind regime. The water inflow level does NOT have any impact on the results. This means that the only difference between the years is the wind since we have the same load profile for all years. Then the differences in results only depend on how windy it is during hours with rather high demand.

It appears that the ECC method (80 % available capacity) gives the highest capacity credit whereas the EFC method (100 % available capacity) gives the lowest capacity credit. The result of the ECC method is, however, very much dependent on the assumed availability of the conventional plant. If an availability of 90 % had been assumed instead of 80 %, this method would result in lower capacity credits than estimated.

It also appears that using the standard ECC method (assuming one large unit) and using the 80 % availability, it is not possible to reach the same level of reliability as with the wind turbines. **In other words; the wind turbines has a higher capacity credit than any (any size) single unit with 80 % availability.** Therefore, the standard ECC method has been modified to three units of equal size instead of one large unit.

Table 26 below shows the incremental/marginal capacity credit values. The first column with figures shows the capacity credit of the first 800 MW installed wind power. These figures are the same as in Table 25. The second column with figures shows the capacity credit of the next 200 MW wind power (assuming the first 800 MW has already been installed), and finally, the third column with figures shows the capacity credit of the next 200 MW again (assuming that the first 1,000 MW has already been installed).

Table 26: Overview of capacity credit results – incremental/marginal values in %

	800 MW	+ 200 MW	+ 200 MW
2016 – Dry hydrological year (2006 hydro and wind data)			
- ELCC	21.3	11 .6	10 .4
- EFC	19.7	9.8	8.6
- ECC (1 unit)	∞	-	-
- ECC (3 units)	31.1	25 .6	30 .0
2016 – Average hydrological year (1993 hydro and wind data)			
- ELCC	15.2	5.7	4.8
- EFC	12.5	3.5	3.3
- ECC (1 unit)	∞	-	-
- ECC (3 units)	17.3	6.0	4.5
2016 – Wet hydrological year (1984 hydro and wind data)			
- ELCC	20.1	10 .4	9.1
- EFC	18.1	7.8	6.6
- ECC (1 unit)	∞	-	-
- ECC (3 units)	27.4	18 .0	16 .5

It appears from the table that for the ELCC and for the EFC method the incremental/marginal capacity credit value is decreasing when the penetration level is increased. This is also in line with earlier explanations in this report. For the ECC method, however, the capacity credit value is in one of the cases increasing for increased penetration level.

The three different methods come to different results with regard to capacity credit. This might seem contradictory, but it is not, because the three different methods/results are expressing three different things:

- › The ELCC figures tell how much the demand can be increased (as a consequence of the wind turbines) and still having the same LOLP in the system.
- › The EFC figures tell how much 100 % available capacity that can be replaced by the wind turbines and still having the same LOLP in the system.
- › THE ECC figures tell how much conventional (in this case 80 % available) capacity that can be replaced by the wind turbines and still having the same LOLP in the system.

So the three different types of capacity credit figures simply just provide three different types of information. The choice of what figures that should be used depends on the purpose in the specific situation. If the purpose is to estimate how much conventional power capacity that can be replaced by the wind turbines and still having the same LOLP in the system, then the ECC method is the method expressing that figure. This method is, however, as also stated earlier very much dependent on the assumed availability of the conventional capacity.

3.5 Wind regime for Uruguay

In the chapter 3.4 capacity credit has been calculated for the year 2016, a dry year, an average hydrological year and a wet year. In the calculations wind power production estimates have been used – see 3.4.2 - and the validity of the capacity credit calculations are thus dependent on the energy production estimates made and not least the representativeness of the wind in the selected years. When preparing the energy production estimates a number of assumptions and choices have to be made.

In this chapter we will explain how the wind energy production calculations have been made, explain the reason behind the choices made and analyse how the wind regime in Uruguay impacts on capacity credit calculations. Special attention will be devoted to the wind regime in dry years. This is done in an analysis of the variability in the wind speed and hydro inflow.

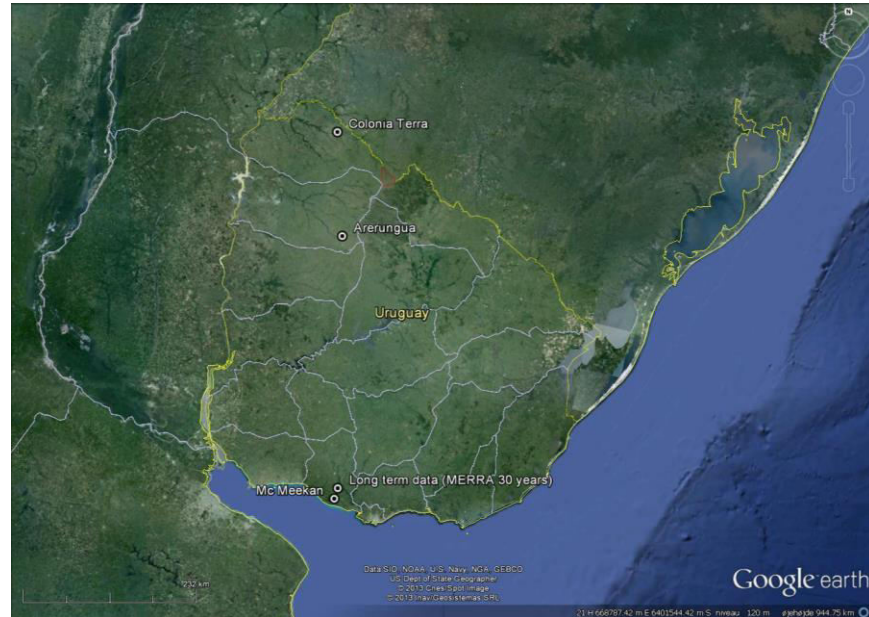
3.5.1 Wind energy production calculations.

Initially, an overall analysis of the wind regime was conducted. A spot check on the measured data was carried out in order to determine if the wind regime covers the entire country. In Figure 22 and Figure 23 it can be seen that the measured wind speed for three different locations (Colonia Terra, Arerungua and McMeekan), presented in Figure 24, follow the same pattern of wind speed and wind direction. Please note that there is a difference in measurement heights (54m, 60m and 101m) leading to a difference in the actual measured wind speed.

Figure 22:

10-min mean wind speed for three positions in UruguayFigure 23: *Wind direction for three positions in Uruguay*

Figure 24: Measurements in Uruguay



Based on the spot checks made it can in general be concluded that Uruguay has a wind regime covering the entire country. In other words when the wind blows it will blow all over Uruguay. There will of course still be differences in wind speed from site to site but in the larger picture it will be minor differences⁵.

The fact that there only exists one wind regime for Uruguay means that the smoothening effect will be limited in relation to capacity credit calculations. But it must be stressed that there will always be some smoothening effect due to geographical dispersion. During the kick-off meeting in February it was agreed to simulate the future wind parks as three larger wind parks – that is a reasonable approximation taking the homogeneousness of the wind regime into consideration but will eventually lead to a little too conservative capacity credit estimation due to the lack of smoothening effect. In order to get some smoothening effect into the calculations it was decided to skip the idea of treating all the sites as one site even though the wind regime is very much the same. A calculation of 30 years hourly production for an installed capacity of 1000 MW was carried out. Subsequently the hourly output was regulated +/- 20% in the capacity credit calculations. The 1000 MW was divided into three wind farms:

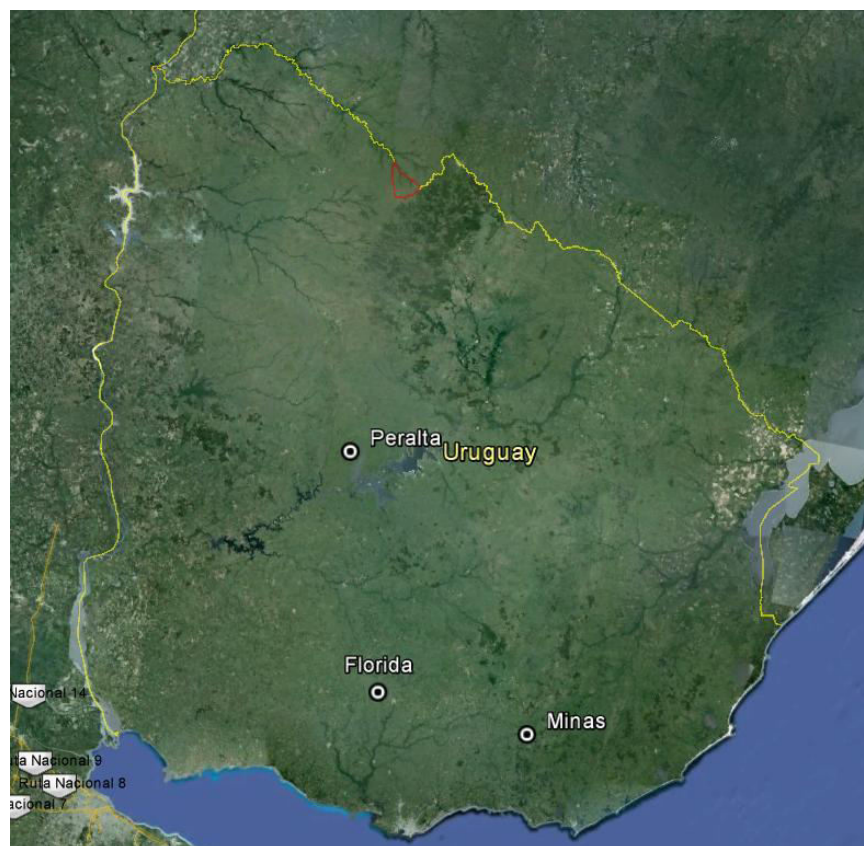
- › Florida/Pintado – 400 MW
- › Minas/Caracoles 3 – 400 MW

⁵ If a more detailed analysis should be made it would be beneficial to prepare a meso – scale wind atlas for Uruguay.

› Peralta – 200 MW

The locations of the wind farms can be seen in Figure 24.

Figure 25: Locations of the three wind farms



3.5.2 Wind raw data

Three years of measurements were available from onsite meteorological masts at three wind farms. The following periods and measurement heights are available:

- › Pintado:
 - › 31-01-2010 – 31-01-2013
 - › Measurement height: 86 m
- › Caracoles 3:
 - › 31-01-2010 – 31-01-2013
 - › Measurement height: 39 m
- › Peralta

- › 31-01-2010 – 31-01-2013
- › Measurement height: 74 m

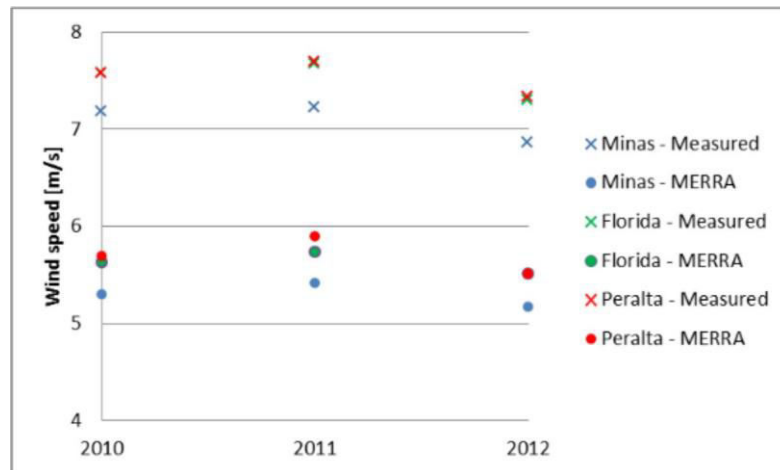
Thirty years of long-term data was available as MERRA (see below) data for three positions close to the meteorological masts, in a height of 50 m. A linear regression has been carried out, presenting a good correlation on a daily average, see Table 27. This correlation was used in order to make the long term data site specific and in the same height as the measured. Furthermore a comparison between the annual wind speed from the three sites for 3-years measurements and the MERRA data has been carried out. If the variations measured are more or less the same the variation in the MERRA data can be considered representative.

Table 27: Correlation coefficients

	R^2
Peralta	0.6324
Pintado	0.6740
Caracoles 3	0.7015

This comparison shows that the variation in the measured wind is almost identical to the variation in the MERRA data, for 2010-2012, see Figure 26.

Figure 26: Yearly wind speed - Measured and MERRA, 2010-2012



MERRA Data

The Modern Era Retrospective-analysis for Research and Applications (MERRA) is a NASA atmospheric reanalysis for the satellite era using Goddard Earth Observing System Data Assimilation System Version 5 (GEOS-5). MERRA focuses on historical analyses of the hydrological cycle on a broad range of weather and climate time scales, including wind data. MERRA data covers the period from 1979 until today.

The data is given in a grid with a horizontal resolution of 2/3 degrees longitude and 1/2 degrees latitude. The data is given as hourly values, starting at 00.30 GMT each day.

Wind Shear

In order to estimate the wind speed at hub height, the power law (eq. 1) has been used with a shear exponent of $\alpha = 0.14$.

$$\text{Eq. 1: } \alpha = \frac{\ln\left(\frac{V_1}{V_2}\right)}{\ln\left(\frac{H_1}{H_2}\right)} \rightarrow V_1 = V_2 \left(\frac{H_1}{H_2}\right)^\alpha$$

3.5.3 Wind turbines

It was decided to use three different types of turbines with different hub height but all within the IEC classification IIA which was deemed suitable for the observed wind regime. The reasoning for not just using one turbine with one power curve at the same height was to get a more realistic hourly energy production for the capacity credit calculations. The following wind turbines have been used for the calculation:

- › Pintado:
 - › Nordex N100 2.5 MW
 - › Hub height: 100 m
 - › Class IIA
- › Caracoles 3:
 - › Vestas V112 3.0 MW
 - › Hub height: 84 m
 - › Class IIA
- › Peralta
 - › Gamesa G90 2 MW
 - › Hub height: 78 m
 - › Class IIA

3.5.4 Losses

In order to get the correct energy production output contribution losses in there must be made a correction for different types of losses. Based on experience from previous production estimates the following losses have been taking into account:

› Wake loss:	5%
› Utility grid availability loss:	1%
› Wind turbine availability loss:	5%
› Transformer and line loss:	2%
Combined loss:	12.4%

Please note that the actual losses depend on the wind farm layout, grid connection etc.

3.5.5 Production Time Series

Based on the hourly wind speed, the corresponding power is found by applying the corresponding power curve and the loss. In the table below is an example of the times series for the three wind farms.

Table 28: Example of energy production by the hour aggregated for three wind farms

Date	Time	Wind Speed [m/s]	Power [kW]
01-01-1983	00:00	7.7	143809.8
01-01-1983	01:00	8.0	159664.8
01-01-1983	02:00	8.1	167544.8
01-01-1983	03:00	8.0	156251.0
01-01-1983	04:00	7.6	138400.6
01-01-1983	05:00	7.5	129745.9
01-01-1983	06:00	7.6	139482.4
01-01-1983	07:00	7.7	145432.6

3.5.6 Production estimate

Based on data and assumptions presented above, the production has been calculated for every hour in a 30 year period:

› 01-01-1983 – 28-02-2013

The results are as expected rather high capacity factors for all three sites:

› Pintado/Florida:	39%
› Caracoles 3:	42%
› Peralta:	37%

3.5.7 Variability in annual wind speed

Based on the 30 years of MERRA data an investigation of the variability of the wind speed has been carried out on an annual basis. The reason being that if the yearly variations in wind speed are limited there will be no correlation of importance to dry – wet years and furthermore the years dry, average and wet years selected for capacity credit calculations will be representative.

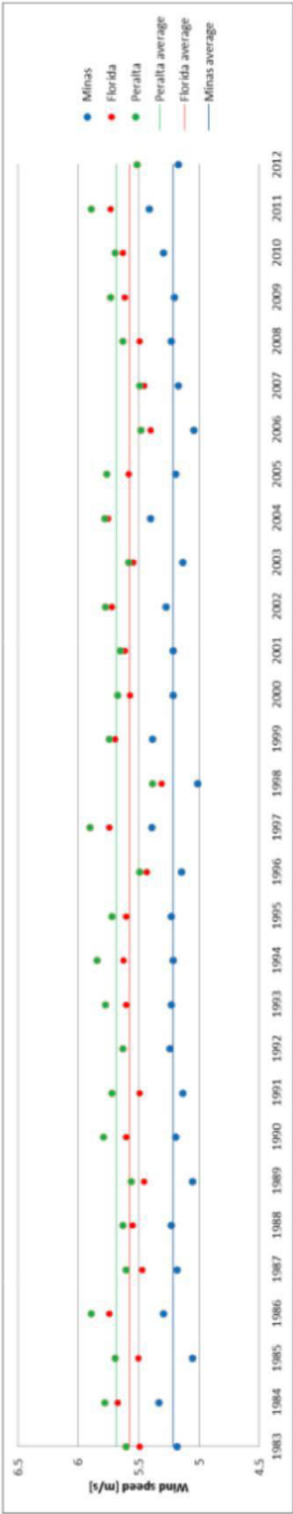
In Figure 27 below, the yearly mean wind speed is presented for the period 1983-2012, for three different locations. The standard deviation in the annual wind speed over the 30 years is approximately 2 % which can lead to variability in the AEP of approx. 4-6 %.⁶

GWh anuales	MW instalados eólica			f. planta	diferencia % respecto al de menor generación		
	800	1000	1200		800	1000	1200
2006	2410,6	3013,3	3615,9	34,40%			
1993	2582	3228,3	3874	36,84%	7,11%	7,14%	7,14%
1984	2653,7	3317,2	3980,6	37,87%	10,08%	10,09%	10,09%
2012		3442		39,29%		14,23%	

⁶ The variability is not the variation between individual years and cannot be compared to the variation between two random years. It is the standard deviation of the 30 year period divided by the average of the 30 year period – describing the variation from average.

COWI

Figure



27: Yearly wind speed, 1983-2012, for three different positions in Uruguay.

Integration of large amount s of wind energy in

Uruguay

3.5.8 Dry years – variability in wind speed and hydro inflow

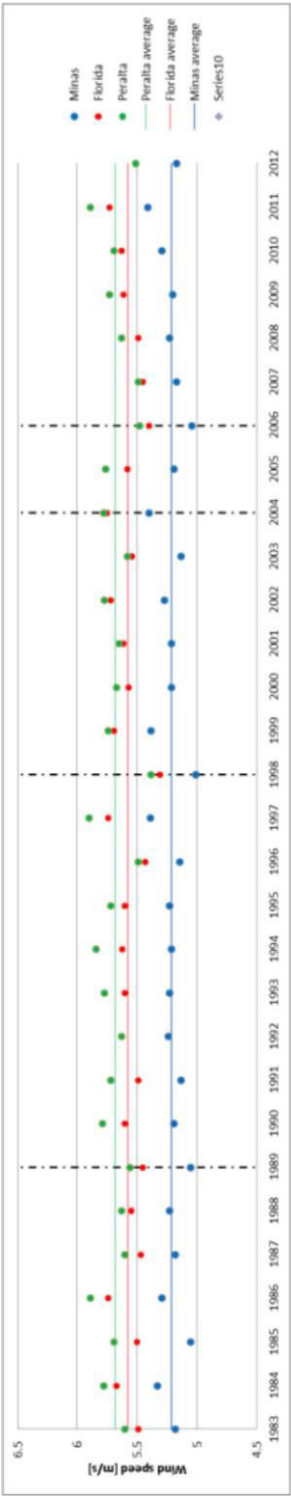
The years 1989, 2004 and 2006 have been categorized as dry years, and it is therefore interesting to investigate the wind regime during those years compared to the hydro inflow. Based on a ranking where the driest year is 1 and the wettest year is 98, these three years have been ranked as 8, 16 and 7 respectively.

Annual

In Figure 28, these three dry years are marked, and it can be seen that the wind speed is lower than the long term average for 1989 and 2006, but higher than the long term average for 2004. Furthermore the wettest year 1998 (ranked 98) is marked in the figure, and it can be seen that the wind speed that year is the lowest of all years.

COWI

Figure 28:



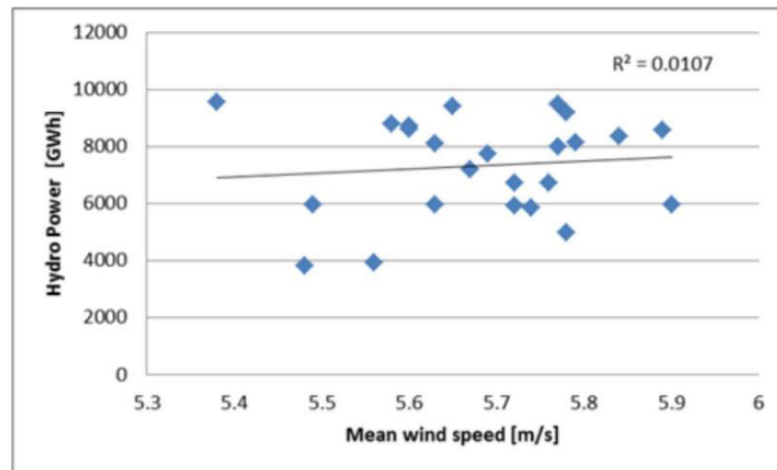
Yearly wind speed – (dry years marked)

Integration of large amount s of wind energy in

Uruguay

In Figure 29, a linear regression between the generated hydro power and the mean wind speed is presented. As it can be seen there is no correlation between the mean wind speed and the hydro inflow from dry to wet years, as the R^2 is 0.0107. In order to conclude a correlation, an R^2 of at least 0.5 should be obtained, and still a good correlation is only present if R^2 is above 0.8. Close to 0 means that there is no correlation at all.

Figure 29: Linear regression between hydro power and wind speed



Quarterly

The two dry years, 1989 and 2006, have been investigated further in order to check if there is any pattern in the wind. In Figure 30 and Figure 31 the average wind speed for the quarterly periods (listed below) are presented together with the sum of the hydro inflow in the periods, for the year 1989 and 2006 respectively. In the figures it can be seen that the wind speed is actually higher in the periods with a high hydro inflow, with an exception of July to September in 2006.

- › January to March (mar)
- › May to June (jun)
- › July to September (sep)
- › October to December (dec)

Figure 30: Quarterly average wind speed and quarterly sum of hydro inflow – 1989

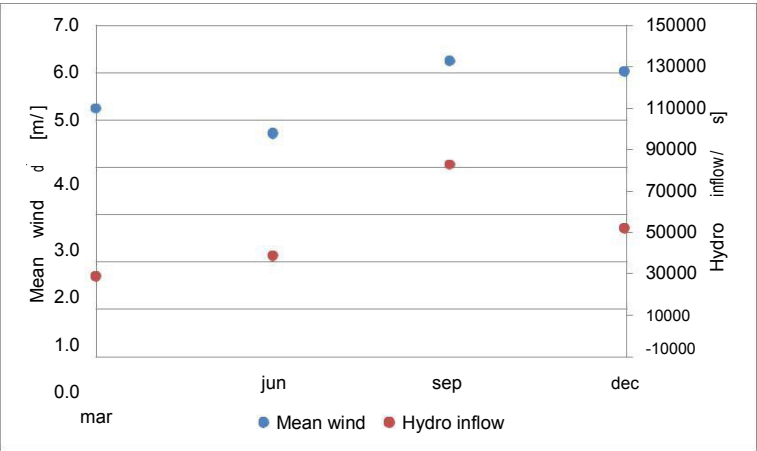
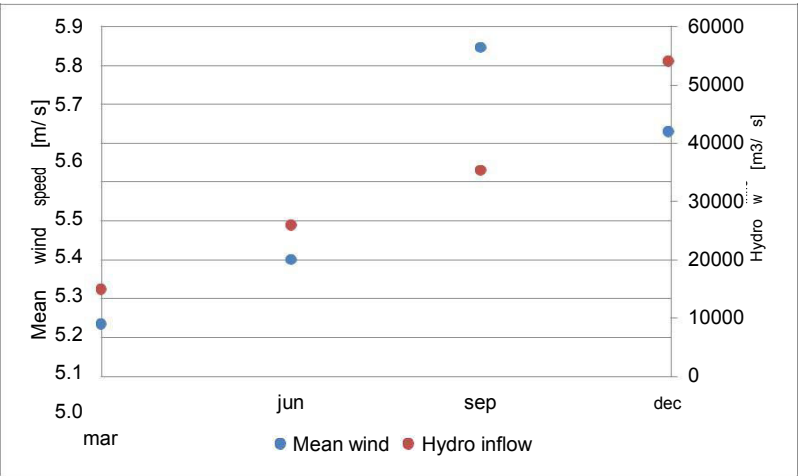


Figure 31: Quarterly average wind speed and quarterly sum of hydro inflow – 2006



Weekly

The same analysis is carried out based on weekly data. Figure 31 and Figure 32 present the weekly average wind speed and the sum of hydro inflow for the years 1989 and 2006, respectively. For the weeks with an inflow below the average the wind speed is both above and below the yearly mean wind speed.

Figure 32:

Weekly average wind speed and weekly sum
of hydro inflow – 1989

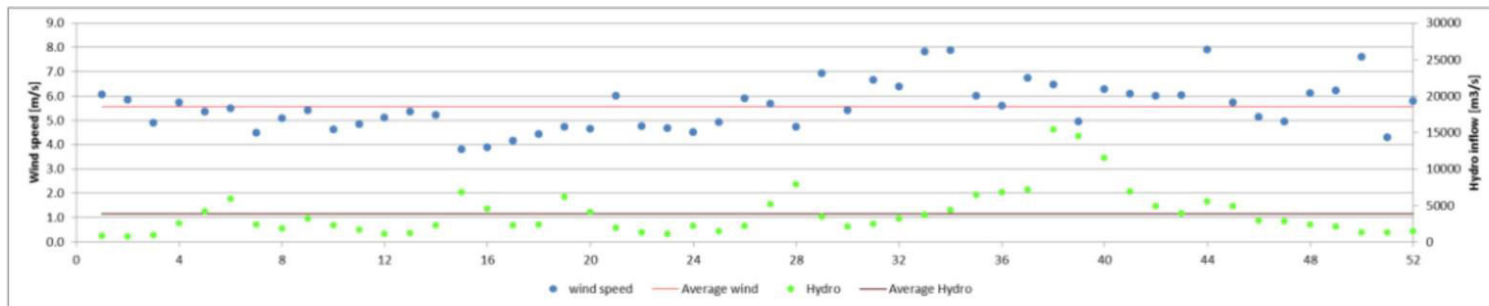
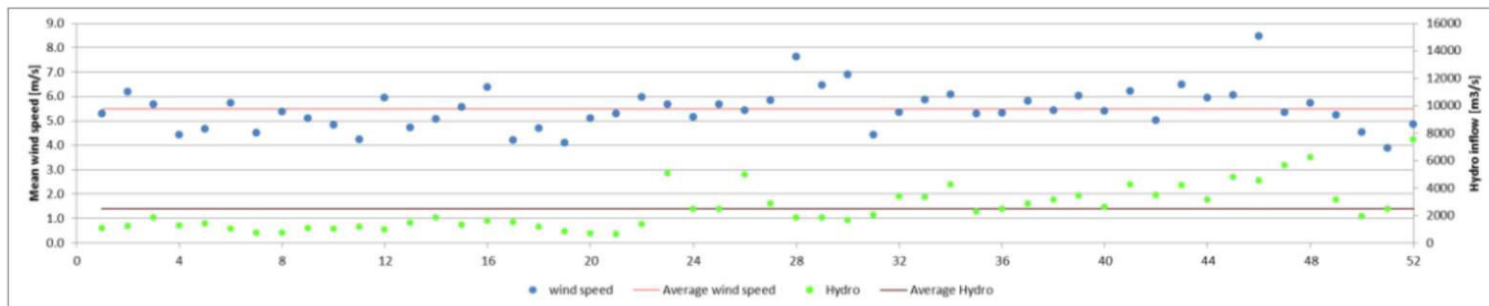


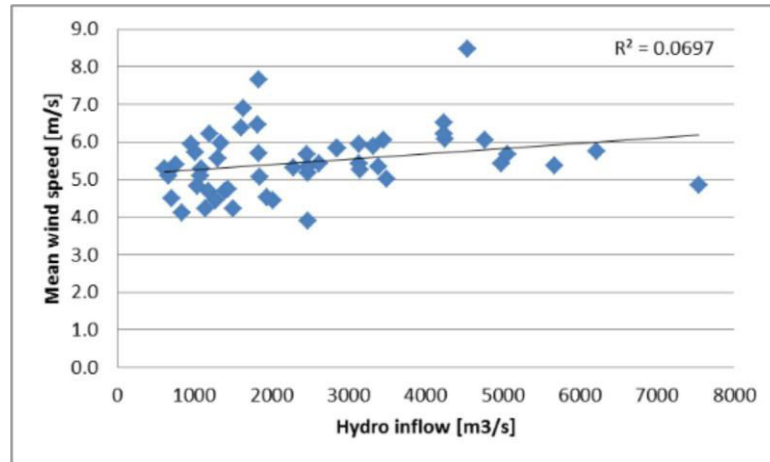
Figure 33:

Weekly average wind speed and weekly sum
of hydro inflow – 2006



In Figure 33 a linear regression between the weekly hydro inflow and weekly mean wind speed is presented. It can be seen there is no correlation as the $R^2 = 0.0697$.

Figure 34: Linear regression between weekly inflow data and weekly mean wind speed



3.6 Implications of the firm capacity and recommendations

Installation of wind power in Uruguay will have a significant positive impact on the power production capacity of Uruguay. Furthermore, it is important to note the capacity credit contribution will be higher during dry years and years with average hydro conditions than for a wet year.

It has not been possible to identify any correlation between dry years and average wind speed not even at dry weeks and wind speed.

Based on the discussions recommendation on regulatory guideline recognizing a capacity credit from wind power plants as a percentage of their nominal installed capacity can be given.

The proposed recommendation should as far as possible result from a consensus between the relevant authorities, suit local market conditions and be possible to adapt into the national regulatory framework.

4 Grid access regulations (component 2)

4.1 Review of international experiences

4.1.1 Europe

The permit application process for grid access is highly variable within European countries depending on regulations, grid ownership and financial responsibilities. Barriers can be realised through the connection of a wind farm to the grid, due to the need for evaluation on many levels by all parties involved. How the parties deal with these barriers effects greatly the quality of the grid access schema in each European nation.

The EWEA has carried out a study called 'Wind Barriers' which looks at building methodology to identify barriers that compromise the development of wind energy, with respect to administration and grid connection. The methodology is to be used by European member of states to promote electricity production for renewable energy sources, here wind power. The findings highlight both successful practices and improvements for the permitting procedures of grid access to wind power plants.

Five main factors have been identified through 'Wind Barriers' as being barriers to grid access and connection:

- 1 Grid connection lead time
- 2 Grid connection costs
- 3 Transparency of decision making process and deadlines
- 4 Number of system operator and number of parties involved
- 5 Physical grid access

Grid connection lead time

Grid connection lead time is often high because of the grid connection procedures. This can be due to a number of factors including poor administration servants, poor administrative deadlines and inadequately defined grid infrastructure. In the EU the average grid connection lead time is 25.8 months for onshore and 14 months for offshore.

EWEA Recommendations:

- › Reduce average grid connection time to 6 months
- › Set and adhere to strict deadlines for administration processes
- › Train and allocate sufficient personnel to manage the anticipated applications
- › Provide well-defined requirements for grid connections and capacities at common coupling points to the public
- › Assign connection points to technically reliable projects over poorly designed
- › Closer collaboration of developer and grid operators
- › Reducing excess of developer requests on grid points by ensuring projects put up for application are realistic and based on measured wind data

Grid connection costs

The grid connection costs here include those for grid extensions, staff and administrative procedures. In some countries, investment risks become high where grid cost information is not well defined or provided early enough in the development process. What's more member states have different regulations on the share of grid connection costs between system operators and developers, which can limit access for some developers. Reports in some EU countries show that connection costs can have significant differences depending on the distribution company, which can affect grid access for developers.

EWEA Recommendations:

- › System operators should cover and/or contribute to the costs of grid connection; protocol defined for this procedure
- › System operators should adapt costs to the project size
- › Limit technical grid connection requirements to what is necessary within the scope of a project
- › Better definition (and eventually EU standardization) of grid codes and connection requirements, which are realistic and correspond with the latest technologies; these are available to developers

Transparency of grid connection process

Grid connection transparency reflects greatly in standards for accessibility to grid connection data, deadlines for the grid connection process, consistency of decision making for allowing connection and collaboration between parties involved. Connections requests would benefit from better coordination between distribution and transmission companies. Grid access would be also fairer where vertical integration of power companies is broken down in some EU countries.

Number of system operators and number of parties involved

In the EU the average number of transmission system operators involved in wind developments is 0.85 for onshore and 0.92 for offshore, which means that a

majority of developments in many countries connect to a single transmission grid. The average number of parties involved in the grid connection procedure in the EU is 24 for onshore and 4.4 for offshore wind. The ideal objective for the EU would be coordination of the application process through a single access point. Currently the best performing countries in the EU have an average of fewer than three entities to contact. For countries where the averages are higher there is concern for clarity in administrative procedure, appropriate interlocutors and the overall decision making processes for grid access procedures.

Physical grid access

In many European countries the grid is underdeveloped in windy areas and/or not capable of integrating large amounts of wind power. This causes problems with grid access where developers have to wait longer to get physical connection to the grid. Farming projects can also be compromised where plants cannot be placed in ideal locations due to this insufficient grid capacity. This supports the need for sufficient funding by and collaboration with the grid operators or energy companies to resist such barriers and provide necessary grid extensions.

A note should also be made on the relation between grid access and access to land for grid connections. It is often the responsibility of the developer to set up evacuation lines connecting the wind park and connection point. In some countries a parallel project with environmental impact assessment studies must be established in gaining approval for this.

Similar access barriers are experienced throughout the EU. The following table also highlights a few and which are most relevant for different regions:

Perceived grid access barriers

Barrier	Administrative or grid	Type of barrier	Austria	Belgium - Flanders	Belgium - Wallonia	Bulgaria	Cyprus	Czech Republic	Denmark	Finland	France	Germany	Greece	Hungary	Ireland	Italy	Lithuania	Poland	Portugal	Romania	Slovakia	Spain	Sweden	United Kingdom	Total
Grid cost paid entirely by the RES-producer	Grid	Market/other	x		x				x	x													x		5
Grid cost split by the RES-producer and DSO/TSO	Grid	Market/other										x						x		x					3
Grid cost paid entirely by the DSO/TSO	Grid	Market/other							x									x							2
Lack of transparent grid connection	Grid	Indicative	x									x					x	x	x		x	x			7
Delays caused by different grid operators	Grid	Measurable		x																					1
No masterplan for grid extension	Grid	Indicative		x														x							2
Limited grid capacity	Grid	Indicative		x	x						x	x	x	x				x	x			x			9
Delays caused by grid operators	Grid	Measurable			x											x	x	x	x			x	x		7
Strict grid access	Grid	Indicative						x										x							2
Individual negotiations for grid access	Grid	Measurable								x															1
High balancing/transport cost	Grid	Market/other			x					x				x								x	x		5

4.1.2 Denmark

Denmark is known for its leading energy market in wind power and is one of the top three countries considered to have a developed growth market in grid connection for wind energy according to 'Wind Barriers'.

Even in the absence of deadlines outlined by the authorities the lead time for a grid permit is on average 2.1 months (compared with EU average of 25.8 months, as

above). While there are no formal deadlines, the cooperation between the Transmission and Distribution System Operators (TSO and DSO) and the developer are efficient, transparent and cooperative. The Danish Order of Wind Turbines sets conditions for splitting of costs for the grid connection between the developer and utilities. These costs are covered by the Transmission and Distribution System Operators, amounting the average project costs in Denmark to at least one-quarter lower than the EU average.

The Danish Wind Turbines Order contains rules for developers regarding the network or transmission supporting the connection, as well as cost shares for connecting and the ongoing connection. The Danish Act of Planning has simplified requirements and straightforward procedures in the regional and local planning areas for grid access for wind turbines. Under the building legislation, wind turbines don't need a building permit only notification to the municipal authority. Type-approval schemes also exist for the simplification of this case processing. Energinet.dk has also established a guarantee fund that allows developers to obtain commercial loans to finance the initial investigations of a wind turbine project. This means that developers and initiative-takers do not become financially insecure in the case where projects cannot be realized. Such funding allows developers to investigate issues such as grid connection at alternative sightings at no cost.

With regards to offshore wind power the Danish Energy Agency is responsible for the overall handlings of a new project. A developer can contain all necessary approvals and licenses through the Danish Energy Agency, who also arranges any consultations with relevant stakeholders. This greatly simplifies the entire application process for new developments.

4.1.3 Brazil

There are a number of parties involved in permitting access to the grid in Brazil. The first point of call is the National Agency for Electrical Energy (ANEEL), who issues licenses for power generation to the developer. They also set fees and conditions for access to and use of grids by permit holders. With this license the developer can apply for memberships and grid connections through the National Grid Operator (ONS). The National Combined System (SIN) combines the entire electrical power generation and power transmission sector of Brazil. ONS controls and manages SIN under supervision of ANEEL.

In Brazil there is a law regarding the principle of free access to the electrical grid. Every producer and consumer has the right to grid connection and use. Users can apply for both permanent and temporary connections to the grid. However a permanent connection can be established faster. Access can be requested from ONS, where the connection is to the transmission grid or transmission installations connected directly to the transmission grid. However, access should be requested from the power supply company where the connection is to the transmission grid or the transmission installations that are not connected directly to the transmission grid.

Application for grid access takes a specified form with appropriate authorization/recommendations at each step. The processing duration depends on the needs for improvements to the proposal. The developer willing to connect to the grid is responsible for conducting all studies supporting their case. Studies should cover energy quality, possible short circuits and power flow. Before making an application it is possible for the developer to make non-obligatory contact with the ONS regarding access to the grid.

There is a 90 day deadline on the finalization of the Agreement Regarding the Use of the Transmission System with the ONS. In this same period the Agreement Regarding Connection to the Transmission System must also be finalized. Costs for these agreements are outlined by the ONS.

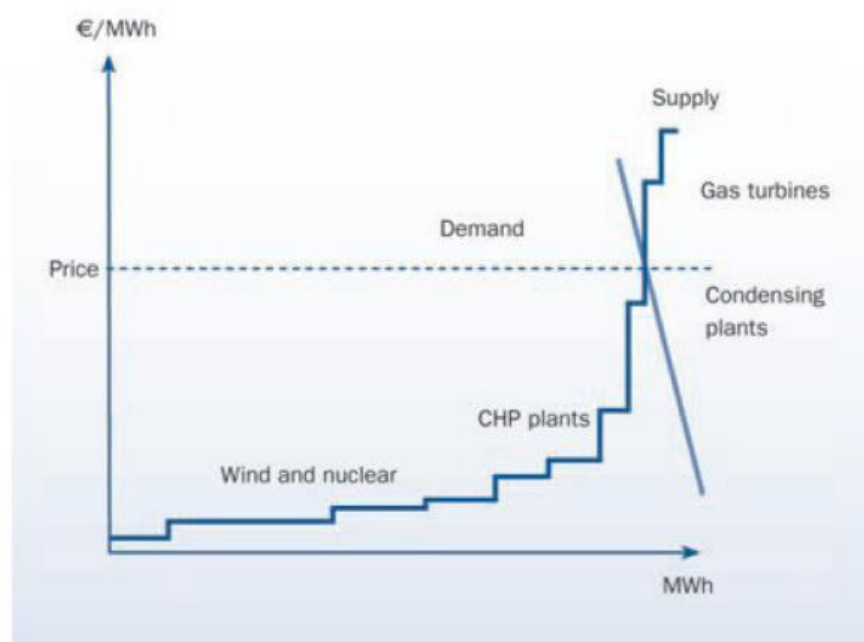
4. 2 Review of methodologies to determine merit order

4.2.1 The merit order curve

In order to minimize the generation costs in a power system, the generators should be ranked in ascending order of their short-run marginal generation costs so that those with the lowest margin costs are the first ones to be put into operation, and the plants with the highest marginal costs are the least ones to be put into operation.

The figure below shows a typical example of an annual supply and demand curve. In a power market, the supply curve is called the "merit order curve". As seen in the figure, such curves go from the least expensive to the most expensive units and present the costs and capacities of all generators. The differences between costs of generators are mainly due to the technology used and the fuel it consumes.

Figure 35: Annual supply and demand curves in the power market



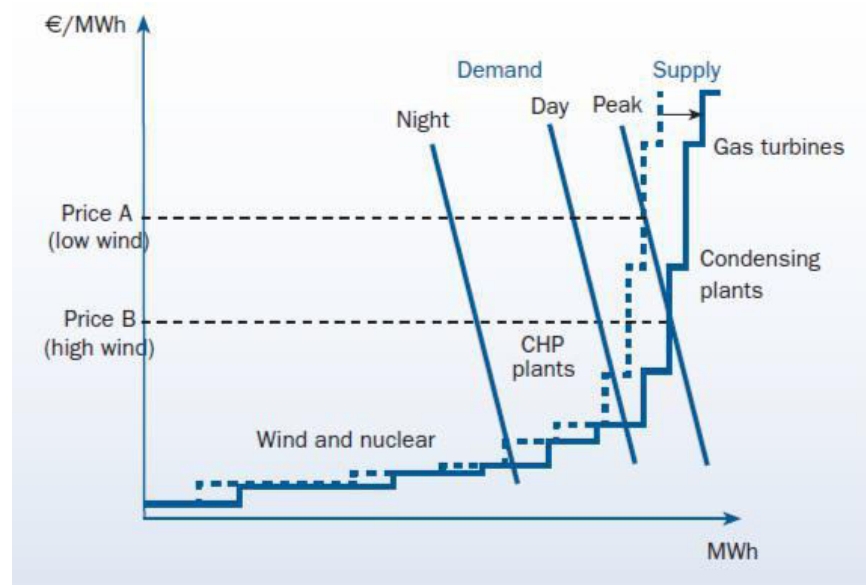
Source: EWEA Economics of Wind

The figure also shows the market price of electricity assuming that there is an electricity market. In this case, the market price will correspond to the marginal generation costs in the system, i.e. the costs of the most expensive generator in operation. However, also in countries/regions without an electricity market, the generators should still be dispatched according to their costs in order to minimize total system costs.

4.2.2 The merit order effect

Wind power normally has a low marginal cost (zero fuel costs) and therefore enters near the bottom of the merit order curve. Graphically, this shifts the merit order curve or the supply curve to the right resulting in a lower power price, depending on the price elasticity of the power demand. In the figure below, the price is reduced from Price A to Price B when wind power decreases during peak demand. In general, the price of power is expected to be lower during periods with high wind than in periods with low wind. This is called the "merit order effect".

Figure 36: Effect of wind power at different times of the day



Source: EWEA Economics of Wind

4.2.3 Curtailment⁷

As explained above, wind has zero or very low marginal costs, which means that as long as a system operates within transmission and operating constraints, wind tends to displace conventional generation. However, increasing wind penetration levels may drive a system to encounter transmission or operational constraints, forcing the system operator to accept less wind than is available. High levels of wind power can be challenging to integrate into power systems because of its variability and limits in predictability. When high levels are planned, infrastructural, operational, or institutional changes to the grid may be necessary. During this transition phase, curtailment may be higher than after the changes are made.

There are many reasons for curtailment, and system operators may distinguish between these reasons for compensation and accounting purposes. The main reasons for wind curtailment are listed below:

- › Transmission congestion, or local network constraints, is a common reason for system operators to utilize higher marginal-prices resources instead of less expensive resources. Related to congestion is insufficient transmission availability. Because of the mismatch in construction times, wind power plants may be built somewhat in advance of the necessary transmission to transport those energy resources to load centers. These new wind power plants may be curtailed until transmission infrastructure is commissioned.

⁷ See also: <http://www.nrel.gov/docs/fy13osti/60245.pdf>

- › Minimum operation levels on thermal generators are another driver for curtailment. Wind is often stronger at night, when loads are low and thermal units are pushed down against their minimum operating constraints. A related issue is the requirement for downward reserve. If wind is unable to provide downward reserves, then sufficient downward capability may need to be held on thermal units, raising their operating levels.
- › Hydro plants may also have a minimum operating levels because of environmental, recreational, or irrigation constraints. For example, to comply with limits on dissolved gases to protect fish, operators may be required to run water through their turbines rather than spill water over a dam.
- › Curtailment can also occur in the distribution system to avoid high penetrations or back-feeding, in which a feeder produces more energy than it consumes, of distributed generation on feeders, which can lead to voltage control issues as a result of variability of the wind resource. Back-feeding can be problematic if protection devices and other infrastructure were not designed or are not yet adapted for this type of operation.
- › Finally, limits may be placed on nonsynchronous generation levels to maintain frequency requirements and stability issues, especially on small, isolated grids. Modern wind power plants interconnect to the grid through power electronics. Because they displace conventional synchronous generation, which provides inertia and may provide governor response, system frequency response might suffer if a contingency event occurs when there is a high penetration of nonsynchronous generation.

Management of curtailment

There are various approaches to how wind is curtailed. There is emerging interest in performing curtailment as part of the market function. The advantage to this approach is that economic signals regarding the cost-effectiveness of alternative curtailment are transparent. If all market participants, including wind power plants, participate, then the solution will be economically efficient. Conversely, when no market mechanism exists or is available for curtailment, a system operator must typically make a decision in real time concerning which plant(s) to curtail. The absence of price signals in this case will likely result in an economically inefficient outcome.

No matter what approach is used, the important thing is that it is the units with the highest marginal costs among the units which it is possible to curtail that should be curtailed. In systems with a high share of both hydro power and wind power, it is therefore necessary to consider the marginal costs of these two technologies in order to decide what should be curtailed. When considering the costs of hydro power with storage, it is important not only to look at the variable O&M costs of operating the turbine. It is important to consider the "opportunity value" if the water is saved for later use. The costs of running the turbine may be very low and this could lead to the conclusion that the costs of hydro generators are close to zero as for wind generators. But if the water can be saved for later use and thereby replace electricity generated at e.g. condensing plants, the water has a value, i.e. the

alternative value of the water at any time in the future, which should be taken into consideration. In this case, the wind power should most likely be curtailed before the hydro power. If there is no storage and the water cannot be saved for later use, then marginal costs for hydro power will probably be close to the marginal costs for wind power.

Examples of wind energy curtailment practices in the United States

The table below is taken from the NREL report "Wind Energy Curtailment Case Studies" from October 2009. It shows some examples of wind energy curtailment practices in the United States.

Table 29: Examples of Wind Energy Curtailment Practices in the United States

	Description	Constrained Operation Procedures	Amount Curtailed	Compensation
ERCOT	Congestion is currently managed by ERCOT on a zonal basis. The majority of wind is near McCamey, in the western zone. ERCOT used special rules for this zone as transmission constraints limited transfers from the zone into the load centers in eastern Texas. ERCOT imposed daily operating limits for wind plants in the McCamey area based on projected generation and demand. This protocol was removed effective Sep. 1, 2009, in preparation for the transition to nodal markets.	ERCOT may call upon wind plants into make reductions in output during periods of transmission congestion. New nodal market rules being implemented.	January to August 2008, curtailed approximately 140-150 MW about 45-50% of the days, via restricted daily operating limits. From December 2008 to July 2009, curtailed between 500 MW and 1000 MW daily, and at times curtailment up to 3000 MW daily.	If McCamey area plants were called upon for curtailment, ERCOT paid out - of - merit energy payments, but only up to the daily operating limit. New nodal market rules being implemented.
Midwest ISO	No specific wind curtailment program. Will curtail wind during Minimum Generation Events along with other generation resources according to economic order.	During Minimum Generation Events, will order curtailments in the following order: 1. Generation identified through the Reliability Assessment Commitment process. 2. Generation above the day-ahead schedule from non-DNRs (Designated Network Resources). 3. Generation above the day-ahead schedule from DNRs. 4. Non-DNR	No ISO-wide data available.	Locational marginal price (LMP) - based market, no additional compensation.

		committed in the Day Ahead Market .		
		5. DNRs and firm imports committed in the Day Ahead Market		
New York ISO	Wind integrated into real-time and day-ahead market dispatch. Wind bids price-quantity curve into real-time market and is dispatched economically along with other generation. Wind plants must participate in wind forecasting and be able to accept electronic basepoint dispatch signals.	During constrained operations generation will be curtailed according to economic bids. Wind plants must follow electronic basepoint dispatch signals within 5 minutes or be assessed penalties for non-compliance.	No data available.	LMP-based market, no additional compensation.
PJM	Wind included in procedures for Emergency Events and Light Load Events. Wind curtailed along with other generation based on economic and emergency minimums. Wind assumed to have minimum of zero unless otherwise bid. Wind plants are required to participate in forecasting system and be able to accept electronic basepoint signals.	During events, all generation reduced to economic minimums first. If additional curtailment needed, all generation reduced to emergency minimum levels. Wind plants are required to respond to electronic basepoint dispatch signals within 15 minutes or must notify PJM if they cannot respond that quickly.	No data available.	LMP-based market, no additional compensation.
Bonneville Power Administration	Curtailment procedures included in wind Large Generation Interconnection Agreement for system events. Wind plants required to participate in forecasting and be able to accept electronic basepoint signals.	When 90% of balancing reserves deployed, BPA can assign generation limits to wind plants based on scheduled output plus a pro-rata allocation of balancing reserves. Wind plants must respond to electronic basepoint signals within 10 minutes or BPA can disconnect the plant.	No data available.	No compensation.
Hawaiian Electric Company	All wind plants are equipped with grid operator controlled curtailment interfaces. Grid operator sets electronic basepoint generation limits as necessary.	During system emergency events grid operator will use most effective controls to address issue (such as reducing a specific wind plant output). During light load times, Must-Run	No data available.	No additional compensation, curtailment is built into contractual agreements.

		<p>Generators reduced to minimum levels, then As- Available</p> <p>Generators (including wind) curtailed according to a pre-determined priority established via contractual agreements.</p>		
Xcel Energy	<p>Northern States Power MN (NSP) is in Midwest ISO and follows the Midwest ISO's direction on whether curtailment is required.</p> <p>Public Service of Colorado (PSCO) and Southern Public Service (SPS) have procedures to reduce all generation and prices/sales to minimum levels prior to ordering wind energy curtailments.</p>	<p>NSP: agreements with wind plants in Southern Minnesota to curtail on a rotational basis when required by Midwest ISO.</p> <p>PSCO: contracts with wind plants to curtail a set amount per year on an as-needed basis. If additional curtailment required PSCO will call wind plants to reduce generation according to a schedule based on the day of the month.</p>	<p>NSP: about 23,000 MWh in 2008.</p> <p>PSCO: about 3,000 MWh in 2008.</p>	<p>NSP: make whole kWh payments for both fixed and variable costs.</p> <p>PSCO: contracted amounts are at no cost. Additional amounts made whole for energy plus Production Tax Credit.</p>
Southern California Edison	Wind curtailment system in place for the Tehachapi region due to transmission constraints.	Agreement with Terra-Gen Power to reduce output on an as-needed basis.	About 15 MW for 3-4 hours about every two days (or 6-8% of the time).	Make whole payment for energy.

Source: "Wind Energy Curtailment Case Studies, May 2008-2009, NREL

Curtailment mitigation options

Reducing curtailment typically involves finding additional sources of flexibility in the system. These can be physical additions (e.g. storage), grid capacity, institutional changes (e.g. access to a new market) or operational changes.

The European Union's Twenties project has studied different mitigation options based on market scenarios for 2020 and 2050 in Northern Europe including countries with significant plans for offshore wind power development. One option is expansion of flexible hydro power and transmission capacity that will reduce wind power curtailment significantly.

4.2.4 Examples from Denmark / NordPool area

In Denmark, on-shore wind turbines in general receive the market price of electricity plus an add-on to the market price. This means that wind operators have an incentive to shut down their wind turbines if the market price becomes sufficiently negative. The add-on to the market price is 250 DKK/MWh and is paid for the first

20,000-25,000 number of full load hours which corresponds to app. 6-10 years (after this period, the wind turbines only receive the market price). By high market prices, however, the add-on is reduced so that the total price within each month (market price + add-on) cannot exceed 580 DKK/MWh.

Even though the wind operators have an incentive to shut down their wind turbines when market prices are negative and where the market price plus the add-on sum up to a price less than 0 DKK/MWh, this only happens very rare. The negative market prices of electricity appear very rare, and when they do, wind operators are normally not prepared for this and not ready to shut down their turbines. During the Christmas 2012, there were some examples that some of the balance responsible in the system had to call wind operators and ask them to shut down their turbines which they had not done by themselves even though they had an economic incentive to do so.

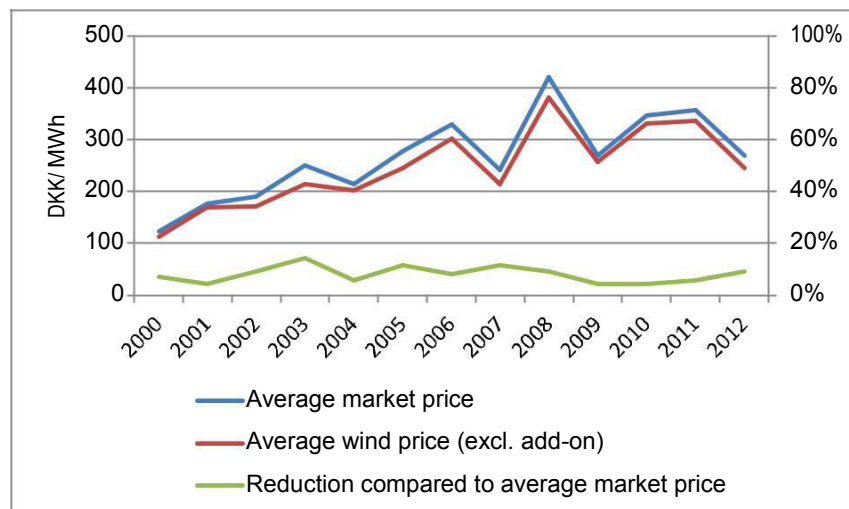
For off-shore turbines, there are some other rules/conditions. They are built based on government tender and they receive a fixed agreed price per MWh. The prices for the three newest off-shore parks are:

- › Horns Rev 2 tendered the 7th of July 2004 – 518 DKK/MWh.
- › Rødsand 2 tendered the 7th of February 2008 – 629 DKK/MWh.
- › Anholt tendered the 30th of April 2009 – 1051 DKK/MWh.

For most of the off-shore wind parks, they receive the fixed agreed price no matter what the market price is, and also if the market price is negative. Thereby, these turbines have no incentive to shut down during periods with negative market prices. For the latest established off-shore wind park (Anholt), however, it has been agreed that they only receive the payment when market prices are positive. In periods where the market price becomes zero or negative, they receive the market price instead of the agreed payment. By this, this off-shore wind park has an incentive to shut down the production during periods with negative market prices.

The two figures below show some data for the western part of Denmark. Figure 37 shows the development in the annual average market price from 2000 to 2012 (blue line). It also shows the average price paid to the wind producers excluding the add-on of 250 DKK/MWh (red line).

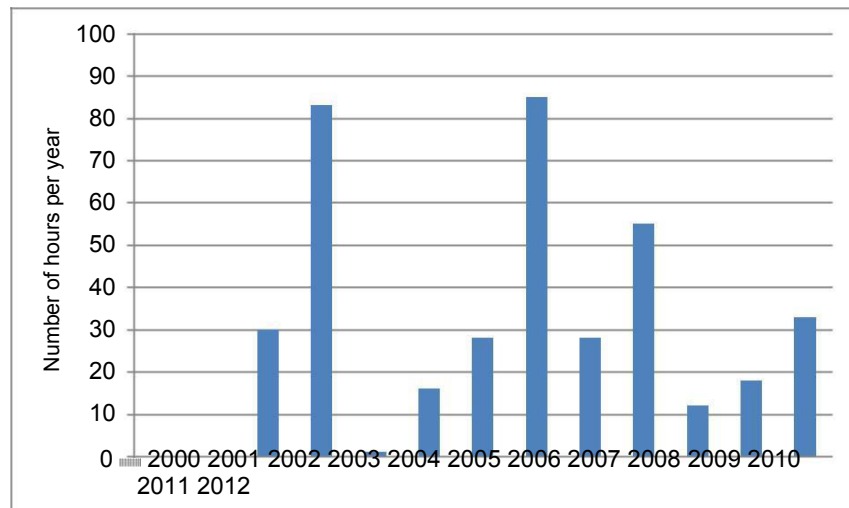
Figure 37: Average market price and average wind price in western Denmark



From Figure 37 it appears that the wind operators in average receive a price (excluding the add-on) which is almost 10 % lower than the average market price. This has to do with the merit order effect as also shown in Figure 36, i.e., the wind turbines are themselves influencing the price in downwards direction.

Figure 38 below shows the number of hours in western Denmark in the period 2000 to 2012 with market prices of zero or with negative prices. It appears that in all years, the number of hours with prices of zero or negative has been less than 100. The reason why it dropped from 2009 to 2010 is the establishment of an electric interconnector (transmission cable) between western and eastern Denmark.

Figure 38: Number of hours with prices of zero or negative prices in western Denmark



5 List of definitions

IDB	Inter-American Development Bank
MIEM	Ministry of Industry, Energy and Mining
UTE	National Administration of Electric Power Generation and Transmission
Capacity credit	The capacity credit is defined as the possibility for a certain power plant to increase the reliability, measured as decreased LOLP, of the power system with a certain level.
Firm capacity	The same as capacity credit
Capacity value	The same as capacity credit
Capacity factor	Capacity factor of a wind turbine is a figure describing the utilization degree of the installed wind farm capacity
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity
ELCC	Effective Load Carrying Capability
LOLP	Loss Of Load Probability
IPP	Independent Power Producers
GEF	Global Environment Facility
Operation cost value	Operating cost value is the capability of the new power plant to decrease the operating costs in the existing power system
Control value	Control value is a value related to the capability of the new power plant to follow the net-load, i.e., load minus production in variable power sources
Loss reduction value	Loss reduction value relates to the capability of the new power plant to reduce grid losses in the system
Grid investment value	Grid investment value refers to the capability of the new power plant to decrease the need of grid investments in the power system
ELCC	Equivalent Load Carrying Capability
EFC	Equivalent Firm Capacity

ECC	Equivalent Conventional Capacity
FOR	Forced Outage Rate
LDC	Load Duration Curve
PPC	Probabilistic Production Costing
ISO	Independent System Operators
RTO	Regional Transmission Organization
MERRA	Modern Era Retrospective- analysis for Research and Applications
GEOS- 5	Goddard Earth Observing System Data Assimilation System Version 5
IEC	IEC = International Electrotechnical Commission
IEEE	Effective Load-Carrying Capability of Generating Units

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Appendix A Explanation of calculations with hydro power including description of "peak - loading"

In this appendix it is explained further how the calculation of LOLP is performed including also how the hydro power (except from the "base-load") is peak loaded in the calculations. If there is then not enough water available, then one has to decrease the amount of available hydro power capacity in order to consider the water limitation (see also Appendix B). However, this limitation was never hit in any of the three hydro years and four wind scenarios (one with 0 MW wind). If there is a surplus of water (which was the case in the calculations), this "extra" water can be used to offload some thermal power plants, which will also happen in real world when doing a least cost optimization/dispatch. But it is important to note that this has NO impact on the LOLP calculation.

A: First it is explained how the calculation of the LOLP is performed:

The calculations of the risk of capacity deficit are performed in the following way.

- a. Start with a specific loading order of all power plants. "Loading order" means that one firstly uses unit number 1, then unit number 2, etc, up to one meets the demand. But since there is sometimes an outage of, e.g., unit number 2, then the loading order is instead, for this case, first unit 1, then unit 3 etc. "Loading order" then means that one decides in which order they will be used. Here we will as unit number 1 have base load hydro power, since this is classified as the part of the hydro power that is used all the time. After the "base hydro", then one takes all the thermal power plants after each other. If there is still a need of more power to meet the demand (also when there is an outage in a thermal power plant), then the peak hydro will be used.
- b. Technically LOLP = Loss Of Load Probability means that during a specific period of the year the available capacity (= Installed capacity minus outages) will not be enough to cover the load. The length of this time (when there is not enough capacity to cover the demand) is then the LOLP. This is in all cases very small and in reality it only happens when there is a combination of high demand, several outages and not so much wind.
- c. As stated in point a) we start to assume that hydro power (except for the "base hydro") is peak loaded. This means that the peak hydro is only used when there is not available capacity enough in "base hydro" + "thermal power". In a second step we then check if there is water enough to produce all this needed extra power (which cannot be covered by "base hydro" + "thermal power"). If there is then not enough water available, then one has to decrease the amount of available hydro power capacity in order to consider the water limitation. However this limit was never hit in any of the three hydro years, and four wind scenarios (one with 0 MW wind). This means that the amount of available water did not in any studied case have any impact on the LOLP in the system.

- d. It can be noted that “peak loaded hydro” leads to a minimum use of water. Since the limit of available water was not hit in any of the studied cases, then there was a “surplus” of water in all studied cases. This “extra” water can then be used to offload some thermal power plants. But it is then important to note that this has NO impact on the LOLP! One has to remember that capacity deficit only occurs when one uses all available capacity (installed capacity minus outages) and “extra water” does not in any way provide extra capacity nor change of amounts of unit outages, so it has NO impact on the LOLP. This means that as long as there is water enough (so one will never cause an outage by lack of water), then the loading order has no impact on the LOLP. So the used loading order from point a) was sufficient for all LOLP calculations.
- e. For the calculations we used so-called “Probabilistic simulations”. The fundamental assumption is that all changes in demand and outages in each calculation are assumed “independent”. This means, e.g. that
 - › Outages in different types of units are as common during peak load as during low load. However one has to remember that “outage” means “not available for production if needed” which is NOT the same as “the unit produced”!
 - › Outages in all units are totally independent from outages in other units. In the calculations we have, e.g., assumed that hydro units are divided into smaller blocks with the assumption of independence between outages in the different blocks. This means, e.g., that if there is an outage in block 1 or not, then the state of this has absolutely NO impact on whether there is an outage in block 2 or not.

Concerning wind power we first calculate the “net-load” for each hour, i.e., [“net load” = “load” minus “wind power”]. This means that one automatically includes the correlation between load and wind in these calculations. This is different in different years. In some years there happens to be high winds when there is high load (lower LOLP), while during other years there is rather low winds during high load (higher LOLP). It can also be noted that this means that

- › Outages in different plants have no correlation to wind speed level, i.e. outages are as common during high winds and during low winds.

It can in addition be noted that the calculations for each year is divided into four periods, but this is mainly done in order to check the water availability during each period.

B: All capacity credit calculation methods are based on calculating the LOLP for different systems, and adjust the systems until one gets the correct LOLP level.

- › **Equivalent Load Carrying Capability- ELCC:** If X MW of a power plant results in that the demand can increase with Y MW at the same LOLP, then the capacity credit as ELCC of the X MW power plant is Y MW. **Method:** 1)

Calculate LOLP without X MW wind power. 2) Add wind power and calculate LOLP again. 3) Adjust the load level (Y MW extra load every hour) until the LOLP is the same as in step 1). X MW of wind power has capacity credit Y MW

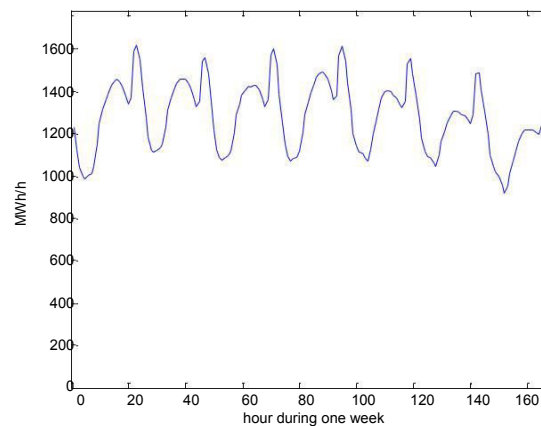
- › **Equivalent Firm Capacity-EFC:** If X MW of a power gives the same decrease of LOLP as a 100 percent reliable Y MW power plant, then the capacity credit as EFC of the X MW power plant is Y MW. **Method:** 1) Calculate LOLP without X MW wind power. 2) Add wind power and calculate LOLP again. 3) Add a 100% available unit to the system with NO wind power (as in step 1) and capacity Y MW. Adjust the capacity level (Y MW installed capacity of the unit) until the LOLP is the same as in step 2). X MW of wind power has capacity credit Y MW

- › **Equivalent Conventional Capacity-ECC:** If X MW of a power gives the same decrease of LOLP as a conventional, not 100 percent reliable, Y MW power plant, then the capacity credit as ECC of the X MW power plant is Y MW. **Method:** 1) Calculate LOLP without X MW wind power. 2) Add wind power and calculate LOLP again. 3) Add T 80% available units to the system with NO wind power (as in step 1) where each has a capacity of Y MW. Adjust the capacity level (Y MW installed capacity of each unit) until the LOLP is the same as in step 2). X MW of wind power has capacity credit $T \cdot Y$ MW. This is done for $T=1$ and $T=3$.

Appendix B A description of how to handle dry year situation concerning LOLP calculation

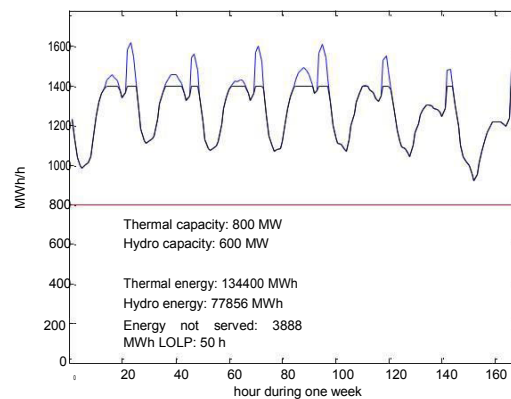
First assume that we have a certain load to manage. In this case it is a weekly load from January from available data, starting with January 2. The load is shown in Figure 39.

Figure 39: Load duration during one week



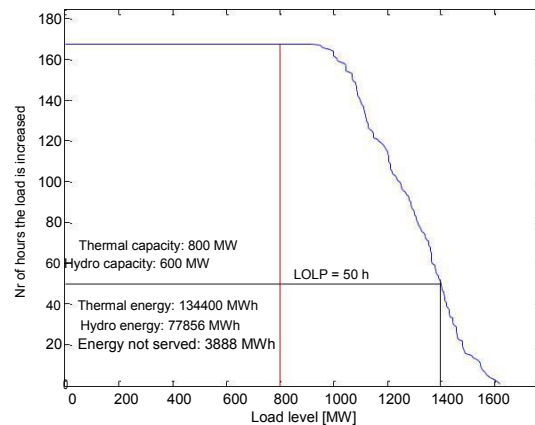
This load should then be covered in some way. Here we assume 100 % reliable thermal and hydro power plants. The thermal capacity is 800 MW and the hydro capacity 600 MW. It is assumed that thermal power acts as base load and the hydro power then produces the rest. The result is shown in Figure 40.

Figure 40: Load covered with thermal power and hydro power



It can be noted in Figure 40 that there is not enough capacity in the system during 50h and the lack of energy production is 3,888 MWh. Figure 40 can be redrawn as a load duration curve which is found in

Figure 41: The load and production from Figure 40 redrawn as a load duration curve



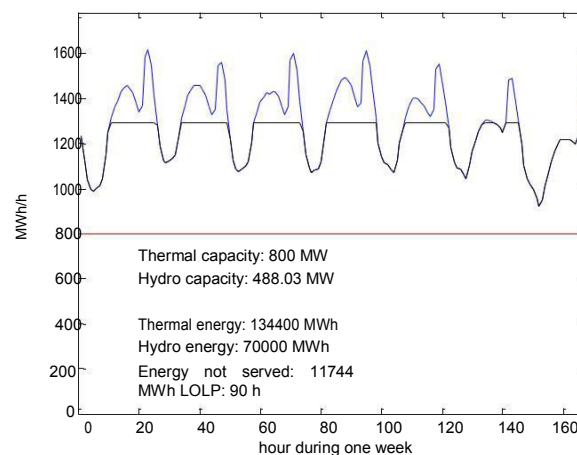
The question of “dry year” then refers to the issue that there is not water enough to cover the required 77,856 MWh in Figure 40. If there is not energy enough then one have to decrease the power production, which will then lead to an increased LOLP and an increased amount of Energy Not Served (ENS). The question is then, in reality, when the hydro power will be decreased and how much. The only formal requirement is that the total energy production has to be the same as available production.

Now assume that only 70,000 MWh is available, i.e., the hydro production has to be decreased with 7,856 MWh. There is a large amount of possibilities to do this, but here only two will be discussed.

Strategy 1 – Decrease hydro power during all hours with the same amount.

The result of this strategy is shown in Figure 42.

Figure 42: Result from strategy 1 – Available hydro power is decreased all hours to fulfil energy restrictions



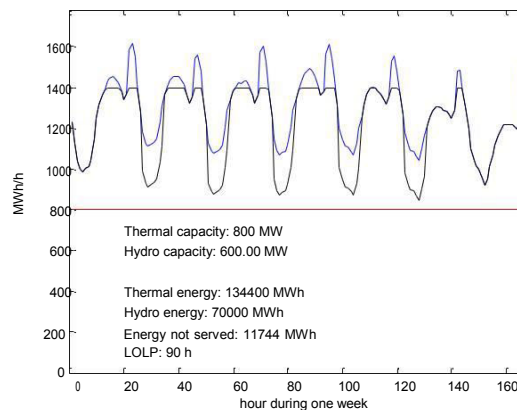
The figure shows that if available hydro power is decrease from 600 MW with 111.97 MW to 488.03 MW, then the resulting energy production becomes the requested 70,000 MWh during the week. The consequence is that the LOLP increases with 40 hours to 90 hours and the Energy Not Served increases with as much as the decrease in hydro energy, i.e. 7,856 MWh.

It can be noted that with a limited amount of water it is essential to use thermal power as base power (no energy limitation) and hydro as peak power, since this means that the capacity of the hydro can be used as much as possible.

Strategy 2 – Decrease hydro power during night s.

Now assume that one think that it is important to cover the peak load, so one instead try to produce as much as possible during day time and decrease the production during night to get the correct energy. An example of this is shown in Figure 43.

Figure 43: Result from strategy 2 with a decrease of hydro power during 8 hours each night



Strategy 2 implies that one decreases the hydro power production each night during 8 hours with 196.4 MW in each hour. Then the energy requirements are fulfilled. The result concerning LOLP and ENS are the same as for strategy 1.

It can be noted that if one decrease hydro during more hours (e.g. 9 hours per night), then the LOLP will increase with 5 hours. If one, on the other hand, decreases hydro power during day time (when there is not enough capacity anyhow) then the LOLP will not decrease. But in all strategies the demand has to be lowered during some hours since there is not water enough.

Selected strategy = Strategy 1

The selected strategy is Strategy 1. The result of this strategy can also be drawn as a load duration curve, see Figure 44.

With this method it is straightforward to apply standard probabilistic simulation. The reason is that outages in thermal power plants are included in the equivalent load duration curve which is considered. If one study, e.g. Figure 43, it looks easy

to control the hydro (less use during night), but in reality one have to consider outages in thermal power plants (perhaps do not decrease in night in there is an outage) which then also have to be considered when the LOLP is calculated. With strategy 1 one can assign the available hydro power capacity in order to get the correct energy production per time period considering both thermal outages (in equivalent load duration curve) and wind power (by using the net load).

Since the same amount of load **energy** is curtailed in any strategy then it should not matter so much if another strategy is used. The ENS is the same in any strategy.

Figure 44: Result of strategy 1, drawn as a load duration curve

