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Políticas de retribución para sistemas fotovoltaicos conectados a red

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UNIVERSIDAD DE ZARAGOZA

Centro de Investigación de Recursos y Consumos Energéticos (CIRCE)

Esta tesis se presenta en la modalidad de compendio de publicaciones

De los cuatro artículos que forman el compendio, tres de ellos se han publicado en revistas con índice de impacto JCR.

1. C.J. Sarasa-Maestro, R. Dufo-López, J.L. Bernal-Agustín, Photovoltaic remuneration policies in the European Union, *Energy Policy*. 55 (2013) 317–328. doi:10.1016/j.enpol.2012.12.011.

2. C.J. Sarasa-Maestro, R. Dufo-López, J.L. Bernal-Agustín, Grid Parity Analysis of PV Markets, in: *Advanced Materials Research*, 2014: pp. 441–445. doi:10.4028/www.scientific.net/AMR.827.441.

3. C. Sarasa-Maestro, R. Dufo-López, J. Bernal-Agustín, Analysis of Photovoltaic Self-Consumption Systems, *Energies*. 9 (2016) 681. doi:10.3390/en9090681.

4. C. Sarasa-Maestro, R. Dufo-López, J. Bernal-Agustín, Evaluating the Effect of Financing Costs on PV Grid Parity by Applying a Probabilistic Methodology, *Applied Sciences* 9 (2019) 425. doi:10.3390/app9030425.

A mi madre, te fuiste igual que viviste, con elegancia
A mi mujer Ana Davinia, llegaste para siempre
To my little Carlotta, a mix of memories
A mi padre, familia y amigos

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1. Introducción

En esta tesis se han analizado las estrategias que se han aplicado, y otras que podrían aplicarse, con el fin de impulsar el mercado fotovoltaico teniendo en cuenta el necesario equilibrio entre sostenibilidad, beneficio y competitividad. Se ha estudiado la situación en España de la paridad de red fotovoltaica, utilizando para ello el Levelized Cost of Energy (LCOE) y la Tasa Interna de Retorno de la inversión (TIR), analizando la opción de incluir autoconsumo. Además, se han realizado varios estudios y análisis con el fin de determinar cuándo y cómo se podría alcanzar la paridad de red fotovoltaica, aplicando para ello cálculos determinísticos y una técnica probabilística (Montecarlo).

En el inicio del desarrollo del sector fotovoltaico, por ser una tecnología de baja eficiencia comparada con otras fuentes de generación eléctrica, y por tener un elevado coste y no estar suficientemente madura, se aplicaron políticas basadas en subvenciones gubernamentales. España y Alemania fueron los precursores en este tipo de políticas. Posteriormente, también las aplicaron Italia, Francia y Reino Unido. Tras esta primera fase, se redujeron las tarifas subsidiarias como consecuencia de la reducción de los costes y de una mejora en la eficiencia de los componentes de las plantas fotovoltaicas, desarrollándose el sector hasta llegar a la paridad con la red, momento en el que la tecnología fotovoltaica llegó a ser competitiva frente a otras fuentes de energía.

En el caso de España, se puede afirmar que el momento clave para el desarrollo de la energía solar fotovoltaica tuvo lugar en agosto de 2005, cuando fue aprobado el plan de Energías Renovables 2005-2010. En ese plan se definieron las políticas energéticas del gobierno, siendo uno de los objetivos prioritarios cumplir con las obligaciones adquiridas por España en el protocolo de Kioto. Otro hito clave fue el avance en la liberalización del mercado eléctrico, que posibilitó la participación de generadores de energía privados.

En otros países se aplicaron diferentes políticas con el fin de favorecer el sector fotovoltaico.

En este documento se describen, de forma resumida, los trabajos que permitieron elaborar y publicar cuatro artículos, que forman el compendio de publicaciones en cuya modalidad se presenta esta tesis doctoral.

En primer lugar, se analizaron las diferentes políticas de remuneración aplicadas en Europa (C. J. Sarasa-Maestro, Dufo-López, & Bernal-Agustín, 2013), estudiando el efecto de estas políticas de remuneración en el mercado global y en las expectativas de los inversores. Las diferentes políticas de remuneración llevadas a cabo en los países miembros de la Unión Europea han sido: Feed in Tariff (FiT), bonos verdes, beneficios fiscales e incentivos a la inversión y subastas de energía.

El FiT ha sido el más utilizado inicialmente. Este sistema es puramente subsidiario y ha sido aplicado por algunos gobiernos con el fin de fomentar la tecnología fotovoltaica y hacerla atractiva a los inversores. Uno de los parámetros que permite evaluar su efecto es la TIR. El valor más atractivo de la TIR para los inversores varía a lo largo de los diferentes países, dependiendo de factores políticos, económicos, sociales y tecnológicos en el momento de la inversión, y durante la operación del activo adquirido.

En la segunda parte de esta tesis se estudió la paridad de red (Grid Parity), analizando varios casos de instalaciones fotovoltaicas conectadas a la red eléctrica en España (C. J. Sarasa-Maestro, Dufo-López, & Bernal-Agustín, 2014). La paridad de red se alcanza cuando el precio minorista de la electricidad es, al menos, igual al coste de generación que se obtiene a partir de los costes de las diferentes fuentes de energía del parque generador: nuclear, gas natural, carbón, petróleo, hidroeléctrica, eólica, fotovoltaica, etc. El parámetro utilizado para el estudio fue el LCOE, que en su cálculo incluye varios parámetros (Branker, Pathak, & Pearce, 2011). El análisis del LCOE permite determinar si una tecnología de generación se encuentra lejos, o cerca, de lograr la paridad de red.

En la tercera parte de esta tesis se analizó la opción de llevar a cabo autoconsumo (C. J. Sarasa-Maestro, Dufo-López, & Bernal-Agustín, 2016). Se comprobó que los costes de la instalación y de los componentes podrían hacer muy competitivo el precio del kWh generado por un sistema fotovoltaico. El propósito principal de este análisis fue determinar cuál es la combinación de fuentes de generación de energía eléctrica más rentable para ser utilizada en una vivienda, considerando en todos los casos generación fotovoltaica. Para ello se tuvieron en cuenta los hábitos españoles de consumo, considerando dos situaciones:

- Sistema aislado con un generador de apoyo y/o baterías.

- Sistema fotovoltaico conectado a la red, donde el usuario puede inyectar la energía que no consume (Net Metering). En este caso se consideró que se aplicaba una política de retribución.

No se consideró necesaria ninguna política subsidiaria, como el FiT, por lo que se utilizó el precio de mercado como referencia para el coste del kWh en España.

En la cuarta parte de esta tesis (C. Sarasa-Maestro, Dufo-López, & Bernal-Agustín, 2019) se llevó a cabo un análisis de sensibilidad con el fin de determinar la situación, en España, respecto de la paridad de red para las instalaciones fotovoltaicas, utilizando como parámetros de estudio el LCOE y la TIR (Van Sark, Muizebelt, Cace, De Vries, & De Rijk, 2012). Para ello se consideraron tres instalaciones fotovoltaicas de diferentes tamaños (5, 50 y 500 kW). El objetivo principal fue determinar dónde y cuándo se alcanzará la paridad de red. Los resultados reflejaron que la paridad de red ha sido ya alcanzada en varios de los escenarios considerados. Se aplicó un método de cálculo determinístico y otro probabilístico (técnica de Montecarlo), determinando el punto en el que se alcanza la paridad de red, donde el subsidio tarifario es cero y la TIR es atractiva para los inversores privados.

El desarrollo de esta tesis se ha llevado a cabo en un marco variable, ya que los costes de instalación y de materiales han ido disminuyendo a lo largo del tiempo. Esta variación de los costes ha influido en los resultados obtenidos en los trabajos de investigación plasmados en este documento.

2. Políticas de remuneración en Europa

En este trabajo se determinó, para cada país, el tipo de incentivo y las tendencias y previsiones de la capacidad fotovoltaica instalada, calculando la TIR de la inversión en sistemas fotovoltaicos conectados a la red.

Los países europeos han aplicado cuatro tipos principales de programas para fomentar el uso de la energía solar fotovoltaica: (1) el FiT, (2) los certificados verdes con un sistema de cuotas, (3) los incentivos fiscales y de inversión, y (4) las ofertas sobre el sistema de cuotas. El FiT es el programa más utilizado para incentivar la instalación de sistemas fotovoltaicos.

Este trabajo se publicó en la revista Energy Policy en 2013 (C. J. Sarasa-Maestro et al., 2013).

2.1 Objetivos y metodología

Los objetivos que se plantearon en este primer trabajo, fueron:

1. Revisar las diferentes políticas de remuneración aplicadas en Europa durante los últimos años.
2. Determinar los niveles de rentabilidad mínimos aceptables para que los inversores privados tengan interés en invertir en nuevas instalaciones fotovoltaicas.
3. Determinar qué políticas de remuneración son las más útiles para promocionar las instalaciones fotovoltaicas.

La metodología que se utilizó fue:

1. Revisión bibliográfica de las diferentes políticas de remuneración aplicadas en Europa en los últimos años.
2. Cálculo de la rentabilidad de varias instalaciones de diferentes tamaños.
3. Con los resultados obtenidos en 1 y 2, se determinó qué políticas retributivas son las más adecuadas para promocionar la instalación de sistemas de energía solar fotovoltaica.

2.2 Revisión bibliográfica y principales aportaciones

La potencia instalada fotovoltaica ha experimentado un notable crecimiento desde 2005 en Europa y en el resto del mundo. La filosofía general ha sido fomentar la energía solar fotovoltaica promoviendo la inversión privada y, por lo tanto, asegurando una rentabilidad atractiva para los inversores. Esta política retributiva ha sido una de las claves para el desarrollo y el futuro de la industria fotovoltaica, ya que la ha convertido en un sector atractivo para los inversores privados al estar su inversión respaldada por los gobiernos. Así, por ejemplo, a pesar de tener menor radiación solar que otros países de Europa, Alemania ha liderado el mercado fotovoltaico desde 2004, y se ha posicionado como líder en Europa, agrupando a un gran número de fabricantes, centros de investigación y desarrollo, así como fondos de inversión.

En la Tabla 1 se indican los países con más potencia instalada durante el año 2018, así como los que poseen más potencia acumulada hasta ese año (International Energy Agency, 2019). Se puede observar cómo Alemania es el primer país europeo, tanto en potencia fotovoltaica total acumulada, como instalada durante el año 2018. Esto se debe a que las políticas que favorecen las instalaciones fotovoltaicas se han seguido aplicando durante los últimos años a pesar de no poseer un recurso solar elevado en comparación con otros países europeos.

El líder indiscutible es China, seguida por Estados Unidos, Japón, Alemania y la India. Considerando conjuntamente los países europeos, la potencia total instalada durante el año 2018 alcanzó los 8,3 GW, y la acumulada fue de 115 GW (International Energy Agency, 2019). Europa posee, por lo tanto, más potencia instalada acumulada hasta 2018 que Estados Unidos.

Tabla 1. Países con mayor potencia fotovoltaica instalada y acumulada en 2018.

Instalada durante el año 2018		**Instalada acumulada hasta 2018**	
País	**GW**	**País**	**GW**
China	45,0	China	176,1
India	10,8	Estados Unidos	62,2
Estados Unidos	10,6	Japón	56,0
Japón	6,5	Alemania	45,4
Australia	3,8	India	32,9
Alemania	3,0	Italia	20,1
México	2,7	Reino Unido	13,0
Corea	2,0	Australia	11,3
Turquía	1,6	Francia	9,0
Holanda	1,3	Corea	7,9

Esta posición destacada de Europa se debe a la aplicación de políticas que han favorecido, durante los últimos años, la construcción de instalaciones de energía solar fotovoltaica. El programa más utilizado para fomentar las instalaciones fotovoltaicas ha sido el FiT, estableciendo una tarifa especial que se aplica a la energía eléctrica generada e inyectada en la red. El FiT es el sistema de remuneración más eficaz para favorecer el desarrollo de sistemas de generación de energía (Couture y Gagnon, 2010). Puede combinarse con una prima sobre el precio de la energía en el mercado al contado.

Este sistema de remuneración puede aplicarse a la energía total generada (FiT bruto), o a la energía resultante tras restarle el autoconsumo (medición neta). En el FiT bruto se remunera toda la energía producida por el sistema fotovoltaico, y la energía consumida por el sistema (por ejemplo, la energía utilizada en una vivienda) se adquiere al precio estipulado en el contrato de consumo de energía eléctrica o en la normativa vigente. Por otro lado, en la medición neta se remunera la energía neta inyectada en la red eléctrica (la energía generada menos la energía consumida por el sistema). Las tarifas de remuneración subvencionadas pueden variar dependiendo del tamaño de la planta, la tecnología y otros factores, y su importe económico puede verse reducido con el tiempo.

Otro programa utilizado por algunos países son los certificados verdes con sistema de cuotas, en el que se obliga a los productores, distribuidores o consumidores, a mantener una determinada cuota de energía renovable. La autoridad reguladora proporciona, de forma gratuita, los certificados verdes a los productores que utilizan fuentes de energías renovables, siendo equivalente un certificado verde a un MWh. El sistema de cuotas se denomina como "obligación de cuota", o "Renewable Portfolio Standard (RPS)" en los Estados Unidos. Los certificados verdes son el principal mecanismo utilizado para implementar este sistema.

El coste del capital es considerado como el principal obstáculo para el desarrollo de la industria fotovoltaica. Por ello es útil aplicar medidas que faciliten la inversión, tales como préstamos, incentivos fiscales, créditos fiscales, impuestos reducidos y amortización acelerada. Los programas de incentivos suelen utilizar una combinación de estas medidas.

Los mecanismos de apoyo financiero han impulsado el desarrollo de la energía solar (Badcock & Lenzen, 2010). En consecuencia, las garantías gubernamentales han favorecido el interés de algunos grupos financieros por invertir en instalaciones fotovoltaicas (Szabó, Jäger-Waldau, & Szabó, 2010), ya que la rentabilidad, las condiciones financieras, y la cuantificación del riesgo, están claramente definidas. Los inversores se han convertido en una parte fundamental de la política energética en todos los países (Bürer & Wüstenhagen, 2009), especialmente en la situación actual en la que el acceso a la financiación es limitado.

Varias medidas se pueden aplicar para fomentar la inversión, como subvenciones y préstamos; o incentivos fiscales, como créditos fiscales, reducción de impuestos y amortización acelerada. Los programas de incentivos suelen utilizar una combinación de estos métodos. Así, los incentivos fiscales del gobierno y el apoyo a la inversión se utilizan para fomentar los sistemas fotovoltaicos, facilitando el acceso al crédito y reduciendo la carga fiscal para la instalación de sistemas fotovoltaicos.

Otro programa empleado en algunos países es el sistema de cuotas, en el que el gobierno realiza subastas públicas para determinados proyectos de generación de energía eléctrica. Cada generador propone sus proyectos, y los ganadores pueden llevar a cabo las instalaciones propuestas con la remuneración resultante de la subasta.

En este primer trabajo se han revisado, analizado y evaluado, los resultados obtenidos con los diferentes métodos de FiT que se han aplicado, durante los últimos años, en varios países europeos con el fin de fomentar el mercado y la industria fotovoltaica (Botero & Morales, 2008).

La Tabla 2 muestra la TIR, y otros datos relevantes, para varios países europeos.

Los resultados corresponden a una instalación típica de 120 kWp en tejado (100 kW de potencia nominal) con un coste de 2,0 €/Wp. El tiempo necesario para llevar a cabo la instalación se ha considerado que es de un mes. La inflación media que se ha aplicado es del 2,5%, y los costes de mantenimiento son del 7% de los ingresos obtenidos antes de aplicar impuestos. El periodo considerado para el estudio económico coincide con el de la aplicación del FiT en cada uno de los países. Toda la energía eléctrica producida por el sistema fotovoltaico se vende a la red eléctrica al precio indicado para cada uno de los países según el FiT aplicado.

Como se observa en la Tabla 2, la diferencia entre los valores de TIR sin crédito bancario (novena columna) y con crédito (octava columna) es sustancial. Los créditos son habituales en la industria fotovoltaica. Se ha considerado una financiación del 80% de los costes de construcción de la instalación fotovoltaica, asumiendo el inversor el 20% restante. El tipo de interés se ha estimado en un 6%. El plazo de amortización del préstamo es de 12 años (11 años más 1 año de carencia), y los pagos del crédito se realizan mensualmente. La TIR calculada se basa en un esquema de financiación que habitualmente se utiliza en la industria fotovoltaica. El flujo de caja anual (por período) es igual a los ingresos menos el coste de mantenimiento después de impuestos.

Tabla 2. TIR y datos relevantes en varios países europeos.

País	Rendimiento Anual Específico[1]	FiT	Impuesto de Sociedades[2]	IVA	Ciclo de vida	Precio de la Electricidad[3]	TIR con Crédito Bancario	TIR sin Crédito Bancario
	kWh/kWp	€/kWh	%	%	años	€/kWh	%	%
Alemania	1250	0,1601	29,51	19	20	0,2282	10,84	8,39
España	1575	0,21	30,00	18	25	0,1720	34,60	15,16
Francia	1275	0,2137	33,33	19,6	20	0,1215	21,00	12,49
Italia	1500	0,233	31,40	20	20	0,1946	37,50	16,02
Grecia (Continente)	1500	0,292	25,00	19	20	0,1061	20,00	21,46
Grecia (Islas)	1500	0,292	25,00	19	20	0,1061	20,00	21,46
Portugal	1500	0,32	25,00	22	15	0,1668	80,00	23,20
Reino Unido	975	0,19	28,00	15	25	0,1347	9,38	7,74
Bélgica	900	VARIOS	34,00	21	VARIOS	0,1896	VARIOS	VARIOS
Bulgaria	1275	0,367	10,00	20	25	0,0865	81,66	25,41
República Checa	880	0,423	19,00	19	20	0,1455	46,52	18,34
Suiza	1100	0,41	25,45	7,6	25	0,1897	108,59	23,03

(1) (PVGIS, 2012), considerando las mejores condiciones del país.
(2) (Taxation and Customs Union, 2012) teniendo en cuenta la energía producida por un sistema fotovoltaico de 100 kW.
(3) Europe’s Energy Portal, 2012

En el caso de España la remuneración a la generación de energía eléctrica, utilizando instalaciones fotovoltaicas, comenzó en el año 2004 (Real Decreto 436/2004, de 12 de marzo, por el que se establece la metodología para la actualización y sistematización del régimen jurídico y económico de la actividad de producción de energía eléctrica en régimen especial), mediante el uso del FiT o subsidios, y se planteó su finalización en el año 2007 (Real Decreto 661/2007, de 25 de mayo, por el que se regula la actividad de producción de energía eléctrica en régimen especial), sin distinción entre instalaciones en suelo o sobre tejado.

En la Tabla 2 se muestra una TIR del 34% para una instalación de 120 kWp. Las tarifas fueron canceladas en 2012, paralizándose la industria fotovoltaica en España.

Recientemente se ha vuelto a favorecer el sector fotovoltaico mediante una legislación que favorece el autoconsumo (Real Decreto 244/2019, de 5 de abril, por el que se regulan las condiciones administrativas, técnicas y económicas del autoconsumo de energía eléctrica), y también con subastas para la instalación de instalaciones basadas en fuentes renovables (Real Decreto 650/2017, de 16 de junio). El gobierno realiza subastas públicas para proyectos de plantas de generación de electricidad. Los grupos inversores interesados pujan, y el ganador es el que firma el contrato con las condiciones especificadas en la subasta.

Los datos de la Tabla 2 muestran que es posible determinar qué política es la más adecuada para las instalaciones fotovoltaicas. Una TIR alta es la mejor opción para los inversores, aunque también hay que tener en cuenta otros aspectos, ya que las condiciones iniciales requeridas podrían hacer más atractivas otras opciones, incluso aquellas con unos valores de la TIR menores.

La mayoría de los países estudiados en este trabajo han utilizado el FiT para fomentar la industria fotovoltaica. Su aplicación presenta diferencias entre países, fundamentalmente en las condiciones o medios de pago. Si bien la TIR varía de un país a otro, estas variaciones son causadas por los riesgos de cada país. Los países de alto riesgo deben estimular un mayor interés en los inversores ofreciendo más beneficios a través del FiT.

El principal indicador para regular el FiT es la TIR de un proyecto, que se sitúa como promedio en torno al 17,5% sin préstamo y al 36% con préstamo (Tabla 2). Podemos concluir, tomando la media de nuestros resultados, que un inversor puede alcanzar una TIR del 17,5% sin préstamo y del 36% con préstamo (excluyendo el raro caso de Suiza). Los gobiernos pueden modificar el FiT cuando la TIR es mayor. La TIR con un préstamo es mucho más alta que la TIR sin préstamo (Tabla 2) porque un préstamo a una tasa de interés relativamente baja (6%) favorece a la TIR. La TIR con un préstamo corresponde a un proyecto que tiene un esquema de financiación típico de la industria fotovoltaica.

Considerando la TIR, las políticas de Suiza, Bulgaria y Portugal son las más atractivas para los inversores en plantas fotovoltaicas. En Suiza, la alta TIR se debe a un elevado FiT, pero esto es inviable en otros países. Por lo tanto, la situación de Suiza no es comparable a la de otros países y no debe considerarse como una alternativa válida para el resto de países europeos, en los que la tendencia es reducir o eliminar las primas y subvenciones a las renovables. Por lo tanto, las políticas de Bulgaria y Portugal deben considerarse como ejemplos de cómo fomentar la energía solar fotovoltaica haciéndola atractiva para los inversores.

2.3 Conclusiones

Los países utilizan cuatro programas principales de pago e incentivos: (a) FiT, (b) certificados verdes con sistemas de cuotas, (c) apoyo fiscal e incentivos a la inversión, y (d) licitación para el sistema de cuotas.

(a) El FiT es el programa de incentivos más utilizado. Algunos países han demostrado que los FiTs fomentan el desarrollo del sector fotovoltaico. Los principales países europeos que han implementado esta estrategia son: Alemania, Austria, la República Checa, España, Francia, Holanda, Italia, Portugal y Suiza. El descenso de las tarifas en varios países no es motivo para dejar de realizar estas instalaciones; el mercado, sin embargo, es a menudo más favorable para un país que para otro.

Un FiT decreciente alcanza su valor mínimo cuando todos los factores involucrados producen una TIR de entre el 15% y el 20%. Cuando la TIR se eleva por encima del 20% los gobiernos disminuyen el FiT. Los programas FiT se centran en los costes de fabricación e instalación, pero es extremadamente difícil prever las tendencias del mercado, ya que todos los países interactúan entre sí simultáneamente.

La Tabla 2 muestra que algunas inversiones son demasiado rentables, dado el panorama financiero mundial. Por esta razón, la presión de una crisis financiera puede dar lugar a que algunos países apliquen reducciones, con carácter retroactivo, en las cantidades que reciben los generadores al aplicar el FiT. En cualquier caso, se debería mantener un rendimiento aceptable para las instalaciones fotovoltaicas (muy por encima de cualquier inversión sin riesgo). Al aplicar de forma retroactiva normas que afectan a la rentabilidad de las instalaciones fotovoltaicas, los países pueden dejar de ser confiables para los inversores, ya que perciben que el nivel de riesgo es elevado dado que en cualquier momento pueden cambiarse las condiciones que, inicialmente, habían considerado para evaluar la posible rentabilidad de su inversión.

b) En Bélgica, Polonia, el Reino Unido y Rumania se utilizan certificados verdes con sistemas de cuotas. Esta política de remuneración es bien aceptada por los ciudadanos que no quieren hacerse cargo de los costes de la tarifa eléctrica.

c) Todos los países europeos apoyan las inversiones con incentivos fiscales. Estos beneficios fiscales pueden aumentar el rendimiento de las inversiones, dependiendo de la configuración de la empresa propietaria de la instalación fotovoltaica y de las normas y leyes de cada país.

d) El contrato con un programa de sistema de cuotas se utiliza para proyectos importantes en Francia. Las experiencias anteriores con este mecanismo en otros países no fueron exitosas debido a los altos costes y a los largos períodos de espera. El Reino Unido e Irlanda han abandonado este sistema, considerándolo ineficiente. Estos programas de licitación han tenido poco éxito en el campo de la energía fotovoltaica. Francia sigue utilizando este complejo procedimiento, pero sólo para sus grandes centrales eléctricas.

3. La paridad de red de la energía solar fotovoltaica en España

El segundo trabajo de esta tesis doctoral dio lugar a un artículo del compendio que fue publicado en la revista Advanced Materials Research (C. J. Sarasa-Maestro et al., 2014).

En este trabajo se definió la paridad de red, de una determinada tecnología de generación, como el punto en el que el precio de la electricidad generada con esa tecnología es, al menos, igual al coste de la energía eléctrica disponible en la red eléctrica, que depende de diferentes tecnologías de generación: nuclear, gas natural, carbón, petróleo, hidroeléctrica, eólica, fotovoltaica, etc. En el caso de la tecnología de generación fotovoltaica, tal y como se muestra en el artículo publicado, la paridad de red depende del coste del sistema fotovoltaico, de la tasa de interés y del coste minorista de la electricidad, por lo que teniendo en cuenta estas variables es posible determinar si los sistemas de generación fotovoltaicos se encuentran cerca, o lejos, de alcanzar la paridad de red.

Varios países europeos han aplicado alguna modalidad de FiT para promover y fomentar la instalación de sistemas fotovoltaicos. España introdujo el FiT en 2004, pero debido a graves problemas financieros y a la incertidumbre de las políticas energéticas, lo revocó en 2012. El incremento del precio de la electricidad ha convertido a la generación de energía, mediante autoconsumo, en una inversión muy atractiva (C. J. Sarasa-Maestro et al., 2016).

En este trabajo se estudia la paridad de red en general, utilizando España como caso de estudio.

3.1 Objetivos y metodología

Los objetivos de este segundo trabajo fueron:

1. Determinar el coste de generación de energía eléctrica de las instalaciones fotovoltaicas.
2. Determinar los diferentes parámetros a considerar con el fin lograr que el coste de generación de electricidad esté por debajo del precio de venta al consumidor.
3. Realizar un análisis de sensibilidad de parámetros financieros para los escenarios analizados previamente y, nuevamente, determinar el coste de

generación de energía (LCOE) con el fin de poder determinar si existe paridad de red para el caso de España.

La metodología que se aplicó fue la siguiente:

1. Revisión de los costes de los materiales e instalación para una instalación fotovoltaica de 6kWp y 5kW nominales.
2. Cálculo de la rentabilidad sin ningún tipo de subvención.
3. Análisis de sensibilidad de los escenarios analizados para el caso de España.

3.2 Revisión bibliográfica y principales aportaciones

En este segundo trabajo se estudió la paridad de red fotovoltaica en España, se calculó el LCOE para diferentes casos mediante un análisis de sensibilidad, y se obtuvieron conclusiones sobre el coste del sistema fotovoltaico y sobre las variables financieras necesarias para lograr la paridad de red.

Es importante destacar que la energía solar fotovoltaica ha sido una de las fuentes de generación de energía más promocionadas, presentando unos riesgos claramente definidos. Esto es ventajoso en la actual economía fluctuante (Bürer & Wüstenhagen, 2009).

Desde la introducción del FiT en España en 2007 (Real Decreto 661/2007), el incremento de los problemas financieros y las cambiantes políticas energéticas han dado lugar a una falta de seguridad dentro del sector, llevando a España a revocar su FiT en 2012.

Cuando se logra la paridad con la red, toda la energía generada privadamente puede ser vendida a la red al mismo precio que se compra para su consumo. En este punto las instalaciones fotovoltaicas se convierten en una inversión sometida al mercado, independientemente de los valores de irradiación o de la cantidad de energía eléctrica producida.

No existe un método de cálculo único para el LCOE, en esta tesis se utiliza uno de los más utilizados (Szabó et al., 2010).

La paridad de red fotovoltaica se define como el punto en el que la electricidad generada por energía fotovoltaica presenta un coste igual o menor al de la electricidad comprada de la red eléctrica (Dufo-López & Bernal-Agustín, 2013).

Los costes de electricidad se clasifican en dos categorías: La primera es el LCOE; el segundo es el precio minorista de la electricidad (Rt), que es el coste que el consumidor final paga por la energía eléctrica que consume.

Al evaluar el LCOE con respecto a la paridad de red, se deben tener en cuenta todos los costes del sistema y del proyecto (Branker et al., 2011). Estos costes incluyen a los paneles fotovoltaicos, las estructuras, los inversores, los cables y los costes de instalación. Es importante tener en cuenta que los valores de depreciación de los componentes utilizados no se consideran, excepto para los paneles fotovoltaicos. Por lo tanto, los costes de todos los demás componentes se considera que son fijos (Tabla 3).

Tabla 3. Coste de un Sistema fotovoltaico de 6.000Wp (5.000W nominales)

	PV Module Cost (€/Wp)				
	1	0.8	0.6	0.4	0.2
Paneles fotovoltaicos (6kWp)	6.000	4.800	3.600	2.400	1.200
Soporte	1.700	1.700	1.700	1.700	1.700
Inversor (5000W)	1.200	1.200	1.200	1.200	1.200
Panel de control y protecciones	800	800	800	800	800
Otros materiales (cables, etc.)	500	500	500	500	500
Mano de obra obra civil	1.620	1.620	1.620	1.620	1.620
Mano de obra instalación eléctrica e ingeniería	960	960	960	960	960
Coste total (€)	12.780	11.580	10.380	9.180	7.980
IVA (21%)	2.684	2.432	2.180	1.928	1.676
Coste total incluyendo impuestos (€)	15.464	14.012	12.560	11.108	9.656
Coste / potencia paneles (€/Wp)	2,58	2,34	2,09	1,85	1,61
Coste / potencia nominal (€/W)	3,09	2,80	2,51	2,22	1,93

Utilizando los parámetros indicados en la Tabla 3, y fijando el precio de venta al consumidor en 17,4 c€/kWh, incluido el IVA, se obtuvieron los resultados mostrados en la Tabla 4.

Se observa que el coste de generación de energía eléctrica solamente llega a ser menor que el precio de venta al consumidor en el caso de que los paneles tengan un coste de 0,2 €/Wp.

Con el fin de analizar este caso se realizó un análisis de sensibilidad, obteniendo el LCOE para varios valores de la tasa de interés, considerando que se había solicitado financiación, para así poder determinar qué condiciones del préstamo pueden permitir que el sistema alcance la paridad de red (Tabla 5).

Tabla 4. LCOE para un sistema fotovoltaico de 6000Wp (5000W nominales) en España

Coste de los paneles (€/Wp)	Coste total (€)	LCOE (€/kWh)
1,0	15.464	0,2519
0,8	14.012	0,2298
0,6	12.560	0,2077
0,4	11.108	0,1857
0,2	9.656	0,1636

Tabla 5. LCOE para varios valores de tasa de interés

Coste de los paneles	Tasa de interés				
(€/Wp)	12%	10%	8%	6%	4%
1,0	0,2888	0,2519	0,2167	0,1838	0,1535
0,8	0,2633	0,2298	0,1979	0,1681	0,1406
0,6	0,2378	0,2077	0,1792	0,1524	0,1278
0,4	0,2122	0,1857	0,1604	0,1368	0,1150
0,2	0,1867	0,1636	0,1417	0,1211	0,1022

3.3 Conclusiones

Observando los resultados mostrados en la Tabla 5, se deduce que una tasa de interés que se encuentre entre el 6% y 8% permitiría alcanzar la paridad de red. Por lo tanto, el autoconsumo comienza a ser atractivo económicamente en mercados como el español. Este resultado enlaza con el siguiente capítulo, donde se analizan los sistemas fotovoltaicos en la modalidad de autoconsumo.

4. Autoconsumo fotovoltaico con sistemas de apoyo

La generación de energía eléctrica mediante instalaciones fotovoltaicas, para aplicaciones de autoconsumo residencial, no puede concebirse de manera aislada, ya que el consumo se extiende a lo largo de las 24 horas del día, y la generación solamente durante las horas de sol. Por ello, puede ser conveniente plantear la generación fotovoltaica conectada a la red eléctrica y/o con almacenamiento. En este tercer trabajo se plantearon y estudiaron varias opciones de apoyo a la generación fotovoltaica.
Este trabajo fue publicado en la revista Energies el 25 de Agosto de 2016 (C. Sarasa-Maestro, Dufo-López, & Bernal-Agustín, 2016).

4.1 Objetivos y metodología

Los objetivos de este tercer trabajo fueron los siguientes:

1. Optimización de sistemas fotovoltaicos residenciales de autoconsumo con almacenamiento y/o conexión a red.
2. Evaluación de la rentabilidad de cada una de las opciones propuestas.
3. Identificación de la solución óptima de generación.

La metodología que se aplicó en este trabajo fue:

1. Identificación y configuración de las diferentes instalaciones propuestas.
2. Combinación de las diferentes instalaciones propuestas con sistemas de almacenamiento con baterías.
3. Análisis financiero de las configuraciones planteadas y optimización del rendimiento financiero.
4. Análisis de sensibilidad de las configuraciones con respecto al precio del panel fotovoltaico.
5. Modelizado mediante el software iHOGA, improved Hybrid Optimisation by Genetic Algorithms (Dufo-López, 2015).

4.2 Revisión bibliográfica y principales aportaciones

Debido al elevado número de programas de incentivos que han sido aprobados en los diferentes países donde se ha implantado la energía solar fotovoltaica, esta tecnología se ha convertido en una de las fuentes de generación energética más promocionadas (Badcock & Lenzen, 2010). En este contexto, existe un contraste entre los distintos mercados fotovoltaicos europeos. Una de las principales diferencias entre los países europeos es la posibilidad de consumir, o no, energía generada después de que se haya medido en el contador de generación (C. J. Sarasa-Maestro et al., 2013). Cuando esta opción está disponible en algún esquema de incentivos, el coste de generación por kWh de energía consumida puede ser más económico que el proporcionado por el operador o distribuidor de red, ya que este sistema remunera al propietario por cada kWh generado. La mayoría de los esquemas de incentivos desaparecen con el tiempo (Cucchiella, D'Adamo, & Rosa, 2015), a medida que crecen los mercados de los países en los que se aplican. Por ello, el propósito principal de este trabajo fue el desarrollo de modelos con el fin de determinar los beneficios asociados al consumo de la energía que se genera en una instalación fotovoltaica, incluso sin que exista apoyo financiero, como el FiT o un certificado de obligación de energías renovables. Suponiendo que se logre la paridad de red, la energía solar fotovoltaica puede venderse a un precio similar al precio de la consumida. Este escenario crea múltiples oportunidades de negocio, especialmente para el generador de energía Una de ellas sería convertirse en un distribuidor de energía residencial o comercial. Este modelo, por lo tanto, crearía una red de generación distribuida.

Hay que tener en cuenta que las condiciones sociales, las fluctuaciones económicas y la estabilidad financiera pueden variar de un país a otro (Bürer & Wüstenhagen, 2009). La mayoría de los países desarrollados, incluidos los Estados Unidos, el Reino Unido, Italia y Alemania, están introduciendo el autoconsumo como principal sistema de desarrollo del sector fotovoltaico (Botero & Morales, 2008). Por ejemplo, los Estados Unidos han promovido el mercado de las instalaciones fotovoltaicas distribuidas utilizando las políticas de medición y apoyo neto (Darghouth, Barbose, & Wiser, 2011).

En el caso de España, la decisión de revocar el FiT (Real Decreto 661/2007, de 25 de mayo, por el que se regula la actividad de producción de energía eléctrica en régimen especial), y el aumento significativo de los precios de la electricidad, pueden convertir al autoconsumo en una actividad muy atractiva a causa de su estabilidad financiera (Dufo-López & Bernal-Agustín, 2015a). En términos de autoconsumo, varios autores han analizado los sistemas fotovoltaicos, tanto económica como medioambientalmente (Talavera, De La Casa, Muñoz-Cerón, & Almonacid, 2014). Para estos estudios se suelen utilizar intervalos de tiempo entre 5 y 60 min, alcanzando buenos resultados (Beck, Kondziella, Huard, &

Bruckner, 2016), aunque para el diseño del sistema de almacenamiento es aconsejable utilizar una resolución temporal relativamente pequeña, de 5 minutos como máximo.

Otros autores han centrado sus trabajos en el uso de baterías, obteniendo como conclusión que su utilización puede favorecer el aumento de las instalaciones de autoconsumo(Luthander, Widén, Nilsson, & Palm, 2015).

A pesar del elevado coste de las baterías, su uso puede ser rentable si el precio de la electricidad es suficientemente elevado (Ondraczek, Komendantova, & Patt, 2015). Si el consumidor paga precios más elevados durante las horas pico de demanda, las baterías pueden dar lugar a ahorros significativos en la factura de electricidad del consumidor (Branker et al., 2011). En algunos trabajos se han estudiado los efectos de la aplicación de los programas de gestión de la demanda, Demand-Side Management (DSM) (Castillo-Cagigal et al., 2011), en combinación con el almacenamiento de energía. Sin embargo, a pesar de los posibles beneficios económicos, existen efectos medioambientales negativos asociados al uso de baterías que no suelen tenerse en cuenta (McKenna, McManus, Cooper, & Thomson, 2013). Estos aspectos medioambientales negativos, si se consideran y se evalúan, podrían disuadir de su uso en los sistemas conectados a la red.

También se han realizado otros estudios sobre sistemas de autoconsumo, de energía solar fotovoltaica, en varios países (Merei, Moshövel, Magnor, & Sauer, 2016), y los resultados alcanzados demuestran que, en muchos casos, el autoconsumo es económicamente viable, aunque su rentabilidad depende de las políticas reguladoras que existan en cada país. Dado que los tipos impositivos aplicables condicionan la rentabilidad de estas instalaciones (Parra & Patel, 2016), se necesita una normativa adecuada con el fin de promover el autoconsumo (Jargstorf, De Jonghe, & Belmans, 2015).

Teniendo en cuenta todo lo anterior, en este tercer trabajo se realizó un estudio sobre el autoconsumo en España (sistemas fotovoltaicos aislados con baterías o generadores diésel, y sistemas fotovoltaicos conectados a la red aplicando políticas de medición neta (Net Metering), centrándose el estudio en parámetros económicos y emisiones de CO_2. El Net Present Cost (NPC) y el LCOE, se utilizaron como parámetros financieros durante la vida útil del sistema (Dufo-López, Cristóbal-Monreal, & Yusta, 2016). En la parte correspondiente al estudio medioambiental se evaluaron las emisiones de CO_2 para el mismo ciclo de vida de todos los componentes.

El estudio realizado se centró en la zona 3 de irradiación de España, que incluye la mayor parte de la zona peninsular, considerando el consumo medio típico doméstico.

Como herramienta para las simulaciones y optimizaciones, se utilizó el iHOGA (Dufo-López, 2015). iHOGA es una herramienta informática de simulación y optimización para sistemas híbridos de generación de energía eléctrica. Utiliza una resolución horaria durante todo un año (que se supone que se repite hasta el final de la vida útil del sistema).

Los resultados financieros y el flujo de caja proporcionados por iHOGA, para la combinación optima de componentes, se muestran en la Figura 1, durante el ciclo de vida de la instalación. El flujo de caja en el último año es sensiblemente menor que en los años anteriores porque se supone que al final de la vida útil del sistema el valor residual de los componentes se recupera al venderlos. Por ejemplo, si al final de la vida útil del sistema (año 25) el generador diésel se encuentra al 50% de su vida útil, entonces es de esperar que se obtenga un flujo de caja al venderlo igual al 50% de su coste de adquisición.

La Figura 1 muestra que, en algunos años, los flujos de caja deben ser más elevados que en otros. En los años decimoprimero y vigesimoprimero el coste es elevado, ya que algunos componentes, como el inversor, deben reemplazarse. Por otro lado, el generador diésel debe ser reemplazado cada dos años. Por lo tanto, cada dos años, el coste de un nuevo generador se añade al flujo de caja esperado para ese año.

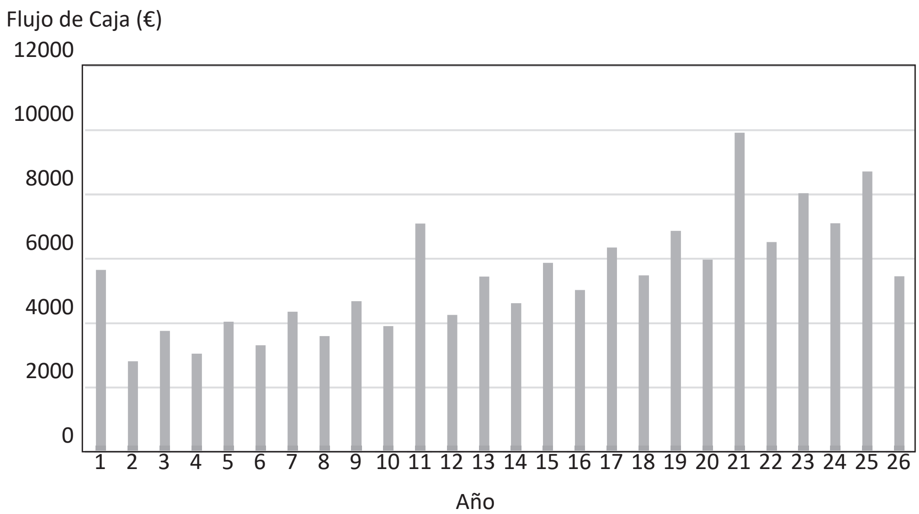

Figura 1. Flujo de caja para el caso de sistema aislado PV + Generador Diésel.

Las diferentes configuraciones del sistema se introdujeron en iHOGA y se simuló su funcionamiento. Se calculó el NPC para todos los casos evaluados, donde la vida útil del sistema se consideró de 25 años (como es habitual para los sistemas fotovoltaicos); el tipo de interés medio considerado fue del 4%; y la tasa de inflación se estableció en el 2%. Los flujos de caja se analizaron anualmente. Los datos introducidos en iHOGA fueron: el coste de los componentes del sistema o capital (CAPEX), la demanda de electricidad del consumidor residencial, los recursos renovables, los parámetros técnicos y los parámetros económicos. Más referencias sobre iHOGA se pueden encontrar en otros documentos previos (Dufo-López & Bernal-Agustín, 2015b).

En este tercer trabajo se consideró que los precios de la energía vendida al consumidor y las políticas de medición neta no variaban durante la vida útil del sistema. Los cambios en las tarifas de venta de energía al consumidor para los sistemas fotovoltaicos distribuidos (Darghouth, Wiser, & Barbose, 2016) y/o la política arancelaria (Darghouth, Wiser, Barbose, & Mills, 2016) pueden afectar a los resultados económicos de los sistemas fotovoltaicos conectados a la red eléctrica.

Las tres configuraciones de autoconsumo estudiadas en este trabajo fueron: sistemas fotovoltaicos aislados con apoyo de generador diésel (Figura 2), sistemas fotovoltaicos aislados con apoyo de generador diésel y baterías (Figura 3) y, por último, sistemas fotovoltaicos conectados a la red considerando Net Metering (Figura 4) (Christoforidis et al., 2016). El NPC y el LCOE se utilizaron para determinar la rentabilidad de las diferentes configuraciones estudiadas. El uso del NPC y del LCOE permite determinar el sistema requerido y los gastos financieros necesarios para cada caso en particular (Branker et al., 2011).

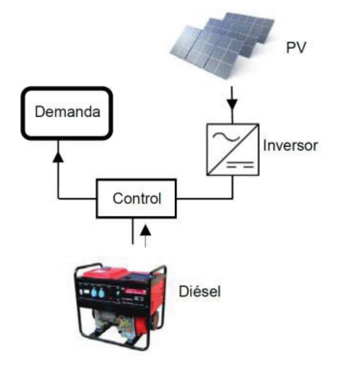

Figura 2. Sistema fotovoltaico aislado + Generador Diésel.

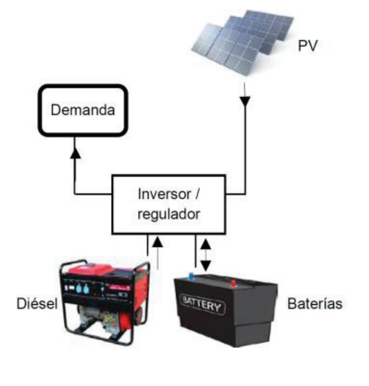

Figura 3. Sistema fotovoltaico aislado + Generador Diésel + Baterías.

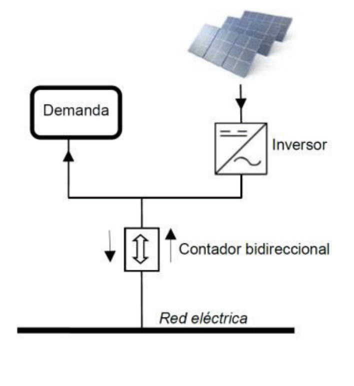

Figura 4. Sistema fotovoltaico conectado a red considerando Net-Metering.

Los resultados óptimos obtenidos con iHoga, y considerando únicamente el punto de vista financiero, proporcionaron los valores del NPC que se muestran en la Figura 5.

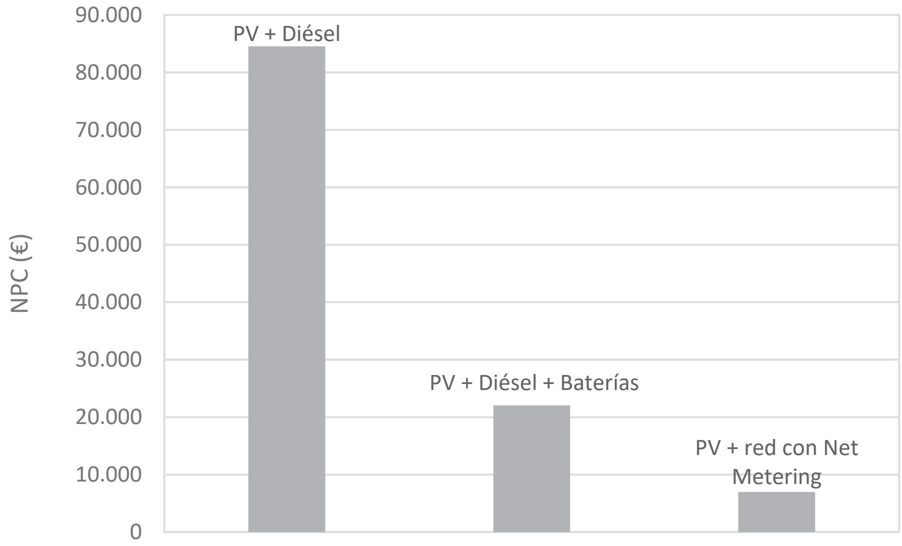

Figura 5. NPC en los tres casos.

El caso de PV + Diésel es el menos atractivo financieramente comparado con los otros dos, mientras que el PV con conexión a red y Net Metering es la mejor configuración.

Teniendo en cuenta los aspectos medioambientales (emisiones de CO2 a lo largo de la vida útil), la figura 6 muestra que PV + Diésel + Baterías da lugar a la menor emisión de CO2.

En este estudio se han considerado las emisiones de CO2 causadas por la producción, el transporte y el reciclaje de las baterías, pero no se han evaluado y considerado todos los impactos ambientales negativos asociados al uso de baterías. Este tema ha sido ampliamente estudiado por otros autores (McKenna et al., 2013), (McManus, 2012), (Balcombe, Rigby, & Azapagic, 2015), y es posible afirmar, basándonos en estos artículos científicos, que la existencia de baterías en el sistema PV + Diésel + Baterías, hace que el sistema PV aislado + Net Metering sea el mejor para el medio ambiente.

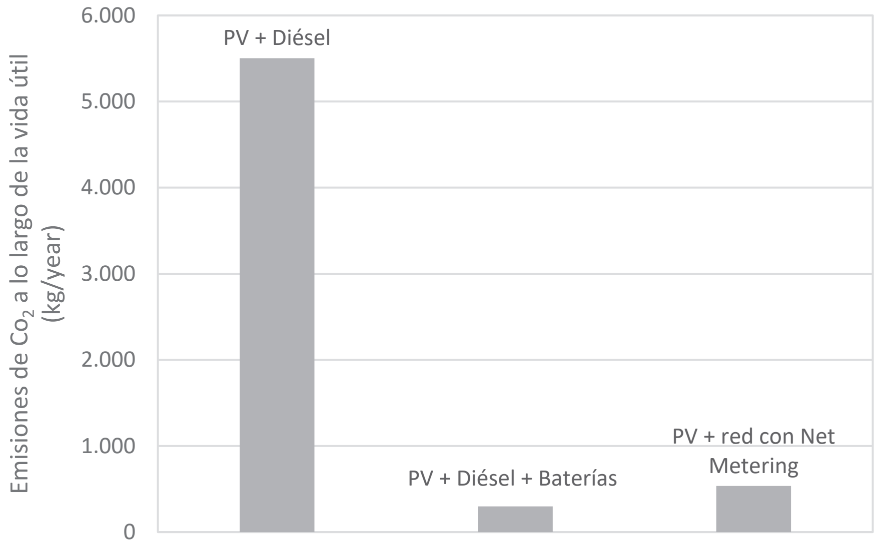

Figura 6. Emisiones de co2 en los tres casos.

4.3 Conclusiones

La Tabla 6 muestra los datos más relevantes de la solución óptima obtenida en cada uno de los casos estudiados.

Tabla 6. Resumen de la solución óptima obtenida en cada caso por iHOGA.

Caso	Aislado/Net-Metering	Configuración óptima				NPC (€)	LCOE (€/kWh)	Emisiones de CO_2 (kg/year)
		Potencia pico (kWp)	Inversor (kW)	Generador Diésel (kVA)	Batería (kWh)			
PV + Diésel	Aislado	5,04	1,8	1,9	N/A	84.546	0,927	5.502
PV + Diésel + Baterías	Aislado	3,92	1,8	1,9	8,64	22.039	0,242	297
PV + Red	Net-metering	2,24	1,8	N/A	N/A	6.992	0,077	536

Los resultados muestran que el sistema fotovoltaico bajo el esquema de medición neta es el que tiene el NPC y el LCOE más bajos, entre dos y tres veces menor que en el caso de PV + Diésel + Baterías, y alrededor de 10 veces menor que en el caso PV + Diésel. Por otra parte, aunque las menores emisiones de CO2 se producen con el sistema PV + Diésel + Baterías, el sistema fotovoltaico en red bajo medición neta es mejor en términos medioambientales porque no utiliza baterías.

Los análisis de sensibilidad mostraron que las variables que más afectan al NPC en el caso óptimo (PV + Diésel) son la inflación anual del precio del combustible y la tasa de interés. En el caso PV + Diésel + Baterías, la inflación de combustible no tuvo una gran influencia en el NPC, pero el precio de las baterías tuvo una influencia importante. En la optimización del sistema fotovoltaico en red con Net

Metering, la única variable que afectó al NPC del sistema óptimo fue el precio de los paneles fotovoltaicos.

5. Evaluación de los efectos de los costes financieros en la paridad de red aplicando la técnica de Montecarlo

En el cuarto y último trabajo de esta tesis se estudió el impacto financiero en los modelos de paridad de red para tres casos diferentes: 5kW, 50kW y 500kW. Como en los trabajos previos, se utilizó el LCOE, la TIR, y el precio de venta al consumidor de la energía eléctrica. Se aplicó un método de cálculo determinístico y uno probabilístico, en particular la técnica de Montecarlo, siendo así posible considerar de forma probabilística las variables que presentan incertidumbre en el estudio de los casos.

Este trabajo fue desarrollado entre los años 2017 y 2018, y fue publicado en la revista Applied Sciences (MDPI) el 27 de enero de 2019 (C. Sarasa-Maestro et al., 2019).

5.1 Objetivos y metodología

Los objetivos de este tercer trabajo fueron los siguientes:

1. Determinar la probabilidad de éxito financiero para los diferentes casos de instalaciones estudiadas (5kW, 50kW y 500kW).
2. Cálculo de rentabilidades aceptables (TIR) para los casos estudiados.
3. Obtención del LCOE para los casos estudiados.

La metodología utilizada en este cuarto trabajo fue:

1. Planteamiento y caracterización de las diferentes instalaciones propuestas para los casos a estudiar.
2. Determinación de las funciones de densidad de probabilidad para las variables.
3. Cálculo del LCOE y de la TIR mediante un método determinístico.
4. Análisis de sensibilidad para todos los casos propuestos y obtención de resultados mediante la técnica de Montecarlo (método probabilístico).
5. Definición y cálculo de la probabilidad de éxito que indica el porcentaje de casos en los que el LCOE queda por debajo del coste de venta al consumidor de la energía eléctrica.

El enfoque y la metodología mostrados en este trabajo son completamente novedosos, ya que permiten estudiar, de forma probabilística, los efectos de los costes de financiación en la paridad de red para las instalaciones fotovoltaicas, siendo posible considerar en el estudio una amplia área geográfica (España en este caso).

5.2 Revisión bibliográfica y principales aportaciones

Para estudiar correctamente cómo puede lograrse la paridad de red es necesario tener en cuenta varios aspectos, como las posibles subvenciones o los regímenes económicos de los generadores fotovoltaicos, así como los costes de financiación de este tipo de instalaciones (Dufo-López & Bernal-Agustín, 2013).

En este cuarto trabajo se estudió la paridad de red fotovoltaica en España, tanto desde un punto de vista determinístico como probabilístico. Se obtuvieron conclusiones evaluando el coste del panel fotovoltaico y el efecto de los costes de financiación (Ondraczek et al., 2015) en la paridad de red fotovoltaica.

El estudio se llevó a cabo considerando tres casos, que corresponden a tres instalaciones fotovoltaicas de diferentes tamaños (5 kW, 50 kW y 500 kW, de potencias de inversor). Además, el LCOE y la TIR se evaluaron tanto de forma determinística como probabilística, utilizando el método de Montecarlo (Geissmann & Ponta, 2017). Varios autores han utilizado el método de Montecarlo para estudiar una amplia variedad de problemas reales. Así, por ejemplo, esta técnica se ha aplicado en el campo de la generación de energía mediante fuentes renovables (Tomosk, Haysom, & Wright, 2017), (Heck, Smith, & Hittinger, 2016), (Pereira, Pinho, Galhardo, & Macêdo, 2014), donde el LCOE y la TIR se han usado para realizar la evaluación económica. En este cuarto trabajo de esta tesis doctoral se han utilizado también estos dos parámetros económicos, ya que se han utilizado habitualmente en estudios llevados a cabo por otros autores obteniendo excelentes resultados. La metodología utilizada, que se ha aplicado a la península ibérica, es fácilmente extrapolable a otros países ajustando los parámetros económicos y energéticos.

En primer lugar, para cada caso, se realizó el cálculo del LCOE; obteniendo el valor más desfavorable mediante un análisis de sensibilidad. El objetivo de este cálculo inicial fue establecer los valores mínimos del LCOE.

Tal y como se ha indicado anteriormente, el primer caso estudiado corresponde a una instalación fotovoltaica de 5 kW (potencia del inversor). El escenario más restrictivo (el peor) corresponde a una financiación con una tasa de interés del 10% y a un ratio de generación de 1100 kWh/kWp, obteniéndose los resultados mostrados en la Tabla 7.

Tabla 7. LCOE y TIR con una tasa de interés del 10% (caso de 5 kW, cálculo determinístico).

Coste de los paneles (€/Wp)	Coste del sistema (€)	LCOE (€/kWh)	TIR (%)
1	15.464	0,2756	−4,811
0.8	14.012	0,2514	−3,83
0.6	12.560	0,2271	−2,68
0.4	11.108	0,2029	−1,31
0.2	9.656	0,1787	0,40

Con los valores obtenidos para el LCOE, se puede concluir que España alcanzaría la paridad de red cuando el coste de los paneles fotovoltaicos sea de 0,2€/W_p. Sin embargo, la TIR a los 25 años, con un préstamo estándar al 10%, presenta un valor positivo muy bajo (0,4%), por lo que la inversión es desaconsejable y poco atractiva (Tabla 7).

En la Tabla 8 se muestran los valores del LCOE para la instalación de 5 kW, utilizando un método determinístico de cálculo, y considerando diferentes ratios de producción anual, desde 1100 kWh/kWp (Zona de irradiación 1) hasta 1500 kWh/kWp (Zona de irradiación 5). Existen casos donde el LCOE es menor que el precio de venta al consumidor de la energía eléctrica, por lo que se puede afirmar que, en determinadas condiciones, la paridad de red ya se ha alcanzado. Los valores del LCOE que se encuentran por debajo del precio de venta al consumidor de la energía eléctrica se han resaltado en negrita en la Tabla 8.

Tabla 8. LCOE para diferentes ratios de producción anual (caso de 5 kW, cálculo determinístico).

			LCOE (€/kWh)				
Coste de los paneles (€/Wp)	**Coste del sistema (€)**	**Ratio de generación (kWh/kWp):**	**Caso 1 1100**	**Caso 2 1200**	**Caso 3 1300**	**Caso 4 1400**	**Caso 5 1500**
1,0	15.464		0,276	0,254	0,236	0,220	0,207
0,8	14.012		0,251	0,232	0,215	0,201	0,189
0,6	12.560		0,227	0,210	0,195	0,182	**0,171**
0,4	11.108		0,203	0,187	**0,174**	**0,163**	**0,153**
0,2	9.656		0,179	**0,165**	**0,154**	**0,144**	**0,136**

La Tabla 8 muestra que un coste de panel de 0,2€/Wp, en zonas con 1200 kWh/kWp (o superior), es necesario para lograr la paridad de red, y que en zonas con un ratio de generación de 1300 kWh/kWp (o superior), la paridad de red podría alcanzarse con un coste de los paneles de 0,4€/W_p.

Con el método de cálculo determinístico, se puede concluir que el LCOE alcanzaría al coste de la electricidad minorista con un tipo de interés del 4% (Tabla 9) para cualquier coste de los paneles.

Tabla 9. LCOE para varios valores de tasas de interés (Caso de 5 kW, método determinístico).

Coste de los paneles (€/Wp)	Coste del sistema (€)	LCOE (€/kWh) Tasa de interés (%):	12	10	8	6	4
1,0	15.464		0,3161	0,2755	0,2369	0,2007	**0,1674**
0,8	14.012		0,2881	0,2513	0,2163	0,1835	**0,1533**
0,6	12.560		0,2600	0,2270	0,1957	**0,1663**	**0,1392**
0,4	11.108		0,2320	0,2028	0,1751	**0,1491**	**0,1251**
0,2	9.656		0,2039	0,1786	**0,1545**	**0,1318**	**0,1110**

La Figura 7 muestra, gráficamente, los resultados de la Tabla 9.

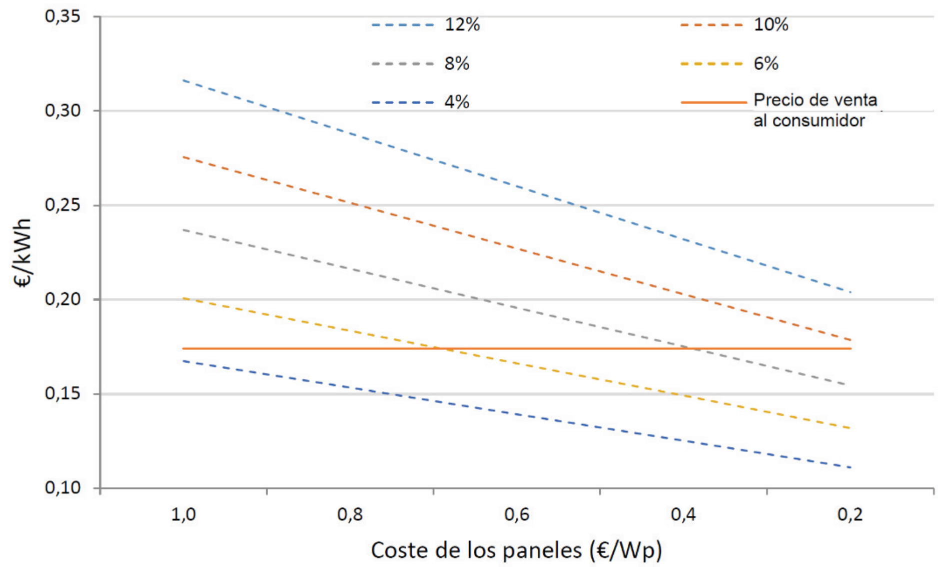

Figura 7. Análisis del LCOE frente al precio de venta al consumidor de la electricidad, considerando varias tasas de interés (Caso de 5 kW, cálculo determinístico).

Para aplicar el método de Montecarlo fue necesario utilizar la Función de Densidad de Probabilidad (FDP) de algunas de las variables involucradas en el estudio. En las Figuras 8 y 9 se muestran las FDPs utilizadas para el ratio de generación y la tasa de interés, respectivamente. Al utilizar la FDP correspondiente al ratio de generación se consideraron los valores que pueden encontrarse a lo largo de la península ibérica. En la Tabla 10 se indican las FDPs utilizadas en este trabajo.

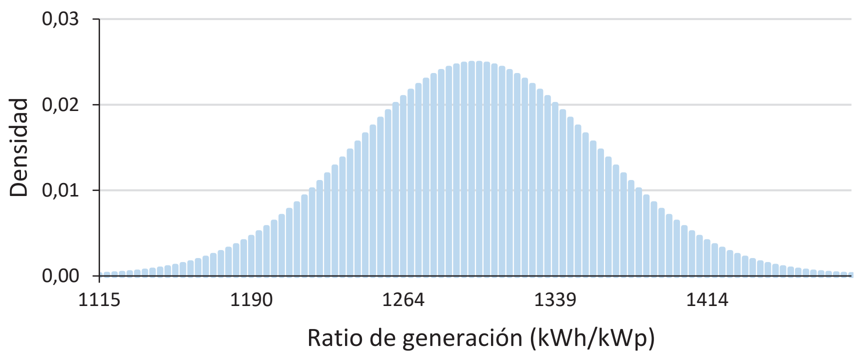

Figura 8. FDP del ratio de generación.

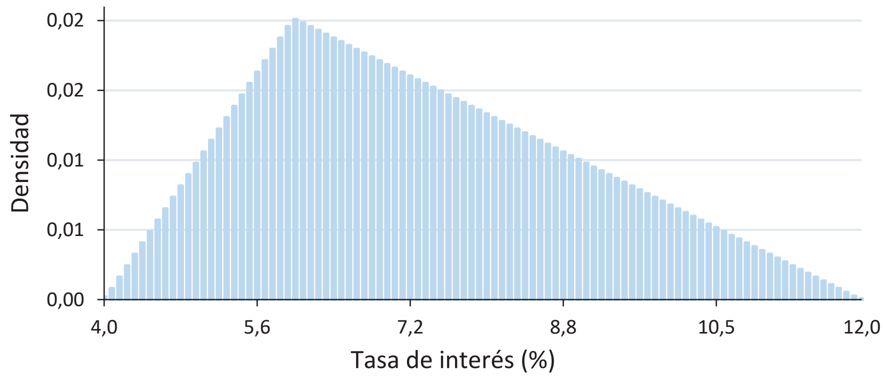

Figura 9. FDP de la tasa de interés.

Tabla 10. FDPs utilizadas en el método de Montecarlo.

Variable	FDP	Rango	Unidades
Potencia de la instalación	Valor constante	6–600	kWp
Vida útil del sistema	Valor constante	25	Years
Ratio de generación	Normal	1100–1500	kWh/kWp
Inversión (CAPEX)	Log-normal	0.2–1	€/Wp
Tasa de interés	Triangular	4–12	%
Precio minorista de la electricidad	Valor constante	0.174	€/kWh

Al utilizar las FDPs de las variables en el análisis probabilístico, aplicando el método de Montecarlo, se obtuvieron las frecuencias con las que era de esperar que pudiesen obtenerse los diferentes valores del LCOE y de la TIR. Se realizaron 10.000 iteraciones en todos los experimentos. Así, en la Figura 10 se muestra el histograma obtenido para el LCOE para el caso de la instalación de 5 kW, observándose que los valores que están por debajo del precio de venta al consumidor de la energía eléctrica presentan una mayor frecuencia.

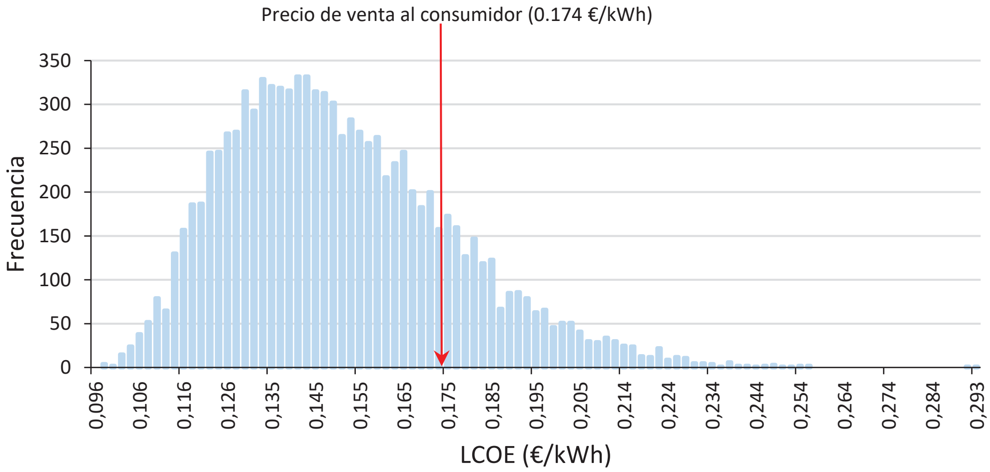

Figura 10. Histograma del LCOE calculado mediante el método de Montecarlo (caso de 5 kW).

El histograma de la TIR, para el caso de 5 kW, se muestra en la Figura 11.

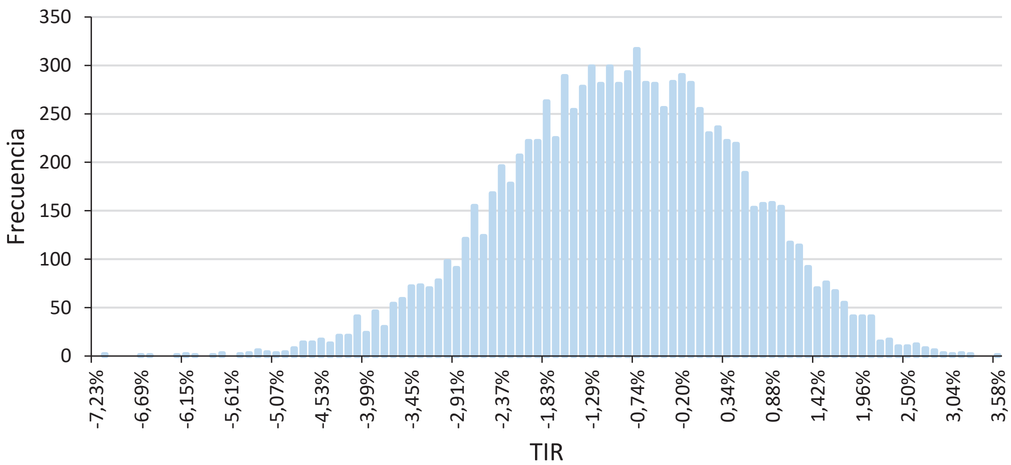

Figura 11. Histograma de la TIR calculado con el método de Montecarlo (caso de 5 kW).

Se utilizó en este trabajo el parámetro tasa de éxito (%), para lo que fue necesario contar el número de resultados que se encontraban por debajo del precio de venta al consumidor de la energía eléctrica, y se dividió ese número por el total de iteraciones (10.000). En el caso de la instalación de 5 kW la tasa de éxito fue del 82,26%. Esto significa que en el 82,26% de los casos se logra la paridad de red, ya que en ellos el LCOE es menor que el precio de venta al consumidor de la energía eléctrica. Sin embargo, la media de la TIR es negativa (−0,97%). Por lo tanto, se puede afirmar que la tasa de interés de la financiación contribuye de forma negativa al éxito de la inversión.

El segundo caso que se estudió corresponde a una instalación fotovoltaica de 50 kW. Aplicando el método de cálculo determinístico, se concluyó que la paridad de red en áreas con un ratio de generación de 1400 kWh/kWp (y superior) ya se ha alcanzado. En zonas con ratios de 1300 kWh/kWp y 1200 kWh/kWp, la paridad de red podría alcanzarse para cualquier coste de los paneles, excepto con un coste de 1€/Wp y un interés fijo del 10% (que corresponde a una situación poco probable).

En las zonas con un ratio de 1100 kWh/kWp la paridad de red ya se ha alcanzado para costes de los paneles que no superen los 0,6€/Wp. Finalmente, se puede concluir que para un coste de 0,8€/Wp, la paridad de red ya se ha alcanzado en zonas con un ratio igual o superior a 1200 kWh/kWp, que en el caso español incluye a la mayor parte del territorio.

Utilizando el método de Montecarlo, se obtuvieron las frecuencias correspondientes a los diferentes valores del LCOE (Figura 12). Se observa que los valores del LCOE que se encuentran por encima del precio de venta al consumidor de la energía eléctrica poseen una frecuencia muy baja.

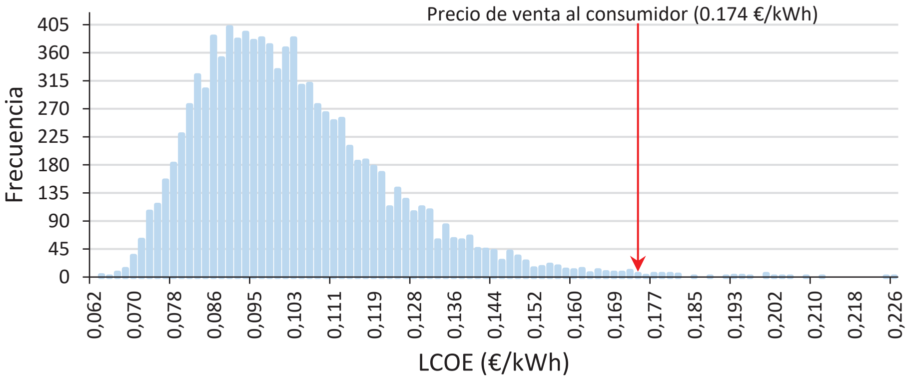

Figura 12. Histograma del LCOE calculado por el método de Montecarlo (caso de 50 kW).

Los resultados de la TIR, aplicando el método de Montecarlo para el caso de 50 kW, se muestran en la Figura 13.

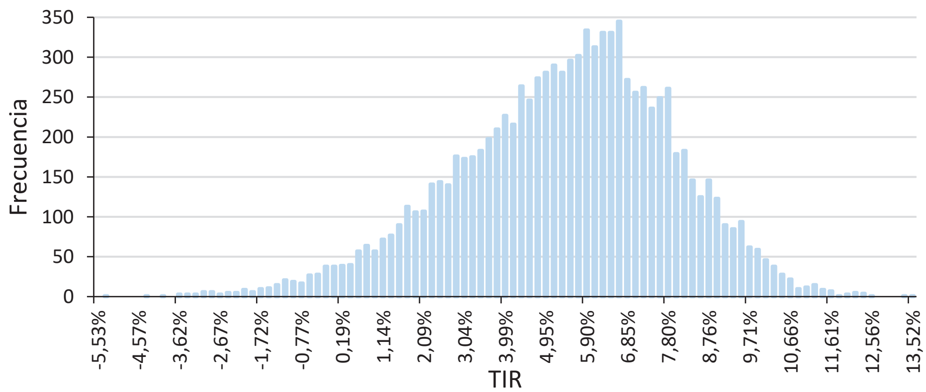

Figura 13. Histograma de la TIR calculado con el método de Monte Carlo (caso de 50 kW).

En el caso de una instalación de 50 kW la tasa de éxito sería del 99,59%. Esto significa que en el 99,59% de los casos se logra la paridad de red, ya que en ellos el LCOE es menor que el precio de venta al consumidor de la energía eléctrica. Además, desde el punto de vista de un inversor, la media de la TIR es positiva (5,29%). Por lo tanto, se puede concluir que la inversión es atractiva.

El tercer caso estudiado corresponde a una instalación fotovoltaica de 500 kW. Mediante cálculo determinístico se pudo determinar que el LCOE alcanzaría el precio de venta al consumidor de energía eléctrica a un tipo de interés del 8% para cualquier coste de panel fotovoltaico, pero también se puede alcanzar a una tasa de interés del 10% y con un coste de panel igual o inferior a 0,8€/Wp. Las zonas con un ratio igual o mayor que 1200 kWh/kWp ya han alcanzado la paridad de red en cualquiera de los casos. En zonas con un ratio de 1100 kWh/kWp, la paridad de red podría alcanzarse para cualquier coste de panel, a excepción del de 1€/Wp. Para un coste del panel igual o menor que 0,6€/Wp, la paridad de red se alcanza en todos los casos, por lo que se puede concluir que, para el escenario actual, la paridad de red ya se ha alcanzado para una instalación de 500 kW.

Aplicando el método de Montecarlo, se obtuvo el histograma de los posibles valores que podía adoptar el LCOE (Figura 4).

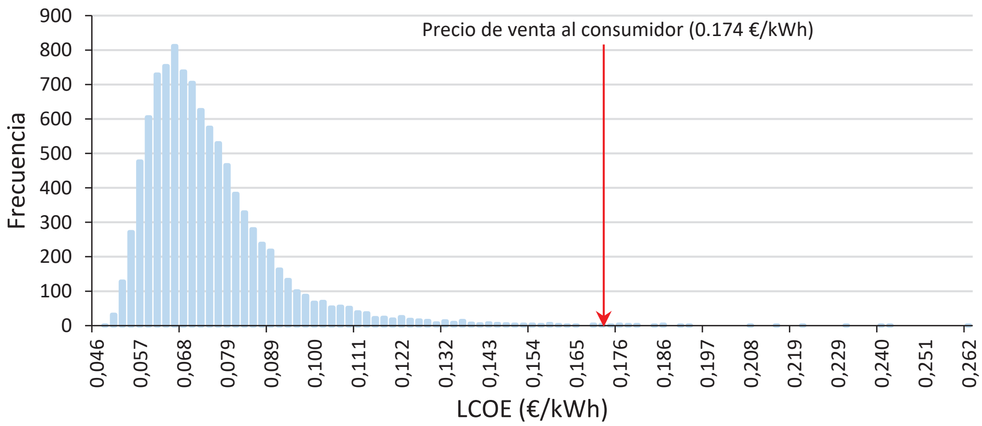

Figura 14. Histograma del LCOE obtenido con el método de Montecarlo (caso de 500 kW).

El histograma para los valores de la TIR se muestra en la Figura 15.

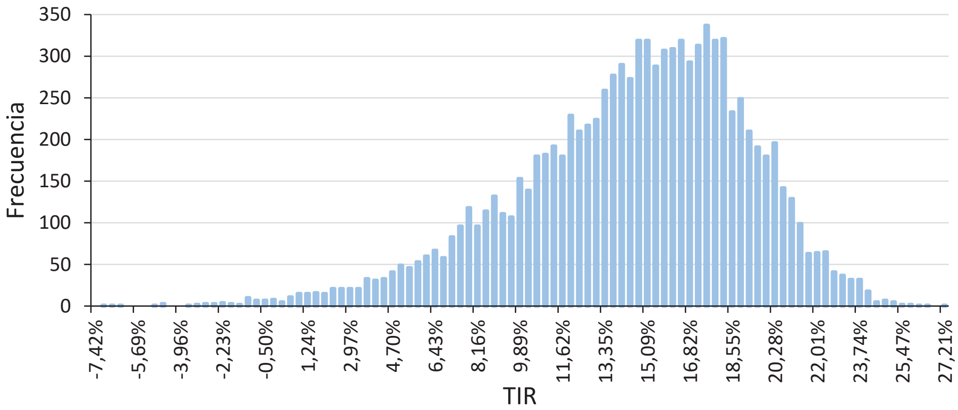

Figura 15. Histograma de la TIR calculado con el método de Montecarlo (caso de 500 kW).

En el caso de una instalación de 500 kW, la tasa de éxito sería del 99,80%. Esto significa que en el 99,80% de los casos se logra la paridad de red, ya que en esos casos el LCOE es menor que el precio de venta al consumidor de la energía eléctrica. Además, desde el punto de vista de un inversor, la media de la TIR es positiva (14,34%). Por lo tanto, se puede concluir que la inversión es atractiva.

5.3 Conclusiones

La metodología de cálculo determinístico nos permite llegar a varias conclusiones. En instalaciones pequeñas, de 5 kW, se alcanzará la paridad de red en algunos casos. En las instalaciones de mediana escala, de 50 kW, la paridad de red ya se ha alcanzado, excepto cuando la instalación se encuentra en una zona con un ratio de generación de 1100 kWh/kWp. Las instalaciones de gran tamaño, de 500 kW o más, han alcanzado ya la paridad de red en todas las zonas de la península, ya que el coste de la energía generada es menor que el coste minorista de la energía eléctrica de la red.

La metodología de cálculo probabilístico, mediante la técnica de Montecarlo, permite llegar a conclusiones que incluyen la incertidumbre asociada a algunas de las variables utilizadas para estudiar económicamente las instalaciones fotovoltaicas. En la Tabla 11 se muestra un resumen de los resultados obtenidos aplicando el método de Montecarlo. Se ha considerado un escenario relativamente pesimista de interés del 10%, siendo su correspondiente factor de recuperación de 0,1102. Se han destacado en negrita los casos en los que el LCOE es inferior al precio de venta al consumidor de la energía eléctrica.

Tabla 11. LCOE calculado con el método de Montecarlo para todos los casos.

Coste de los paneles (€/Wp)	LCOE (€/kWh)		
	5kW	50kW	500kW
1	0,2756	0,2154	**0,1585**
0,8	0,2514	0,1911	**0,1385**
0,6	0,2271	**0,1669**	**0,1184**
0,4	0,2029	**0,1427**	**0,0984**
0,2	0,1787	**0,1184**	**0,0783**

La Tabla 12 muestra los valores medios de la TIR obtenidos tras aplicar el método de Montecarlo, destacado en negrita los casos en los que la TIR es positiva. Se observa que, en algunos, casos la inversión puede ser atractiva.

Tabla 12. TIR calculada con el método de Montecarlo para todos los casos.

Coste de los paneles (€/Wp)	TIR (%)		
	5kW	50kW	500kW
1	−4,81	−2,05	−0,32
0,8	−3,83	−0,53	**1,67**
0,6	−2,68	**1,39**	**4,36**
0,4	−1,31	**3,97**	**8,02**
0,2	**0,40**	**7,46**	**14,52**

Por último, en la Tabla 13 se muestran los valores de las medias del LCOE y de la TIR, así como de los costes de los paneles y del ratio de generación para las instalaciones estudiadas. Además, se muestra la tasa de éxito que se obtiene para cada una de las tres instalaciones que se han considerado. La tasa de éxito, tal y como ya se ha indicado anteriormente, es el porcentaje de casos en los que el LCOE ha quedado por debajo del precio que el consumidor paga por la energía eléctrica. Como se puede observar en la Tabla 13, la tasa de éxito roza el 100% en las instalaciones de 50 y 500 kW. En el caso de la instalación de 5 kW sería necesario realizar un estudio más detallado para poder determinar si la inversión es atractiva, influyendo en el resultado el tipo de autoconsumo que se considere.

Tabla 13. Tasa de éxito y medias del LCOE y de la TIR (método de Montecarlo).

Potencia (kW)	Coste de los paneles (€/Wp)	Ratio de generación (kWh/kWp)	Tasa de interés (%)	LCOE (€/kWh)	TIR (%)	Tasa de éxito (%)
5	0,8	1300	6	0,1494	−0,97	82,26
50	0,6	1300	6	0,1019	5,92	99,59
500	0,4	1300	6	0,0727	14,34	99,80

6. Aportaciones y trabajos futuros

6.1 Aportaciones

Las principales aportaciones de esta tesis doctoral han sido:

- La revisión de las políticas que se han venido aplicando por parte de los países europeos, con el fin de favorecer las instalaciones fotovoltaicas de generación de energía, determinando cuáles son las más efectivas. Este trabajo permitió publicar el artículo: C.J. Sarasa-Maestro, R. Dufo-López, J.L. Bernal-Agustín, Photovoltaic remuneration policies in the European Union, Energy Policy. 55 (2013) 317–328.

  La revista Energy Policy está indexada en JCR, siendo Q2 en dos categorías en el año 2013. Este artículo ha sido citado en 71 ocasiones hasta la fecha del depósito de la tesis (en Web of Science), por lo que puede considerarse como una referencia fundamental dentro de la temática tratada en él.

- El análisis y estudio, en general, de la paridad de red fotovoltaica, aplicándolo al caso concreto de España, y obteniendo como resultado relevante que una tasa de interés de la financiación que se encuentre entre el 6% y 8% permitiría alcanzar la paridad de red. Los resultados de este trabajo se obtuvieron considerando los datos y la situación del año 2014, y dieron lugar a la publicación del artículo: C.J. Sarasa-Maestro, R. Dufo-López, J.L. Bernal-Agustín, Grid Parity Analysis of PV Markets, in: Adv. Mater.Res.,2014:pp.441-445.

  La revista Advanced Materials Research está indexada en Scopus, con un CiteScore rank, en el año 2014, de 0.09 (12th percentile).
  El artículo se encuentra indexado en Web of Science.

- El modelado, análisis y optimización de instalaciones aisladas y conectadas a la red eléctrica, evaluando los resultados económicos y medioambientales que se obtuvieron. Se utilizaron como variables principales el NPC y el LCOE, y se determinó qué factores influyen en mayor medida en la rentabilidad de una instalación fotovoltaica. Este trabajo permitió publicar el artículo: C. Sarasa-Maestro, R. Dufo-López, J. Bernal-Agustín, Analysis of Photovoltaic Self-Consumption Systems, Energies. 9 (2016) 681.

La revista Energies está indexada en JCR, siendo Q2 en una categoría en el año 2016. Este artículo ha sido citado en 6 ocasiones hasta la fecha de depósito de la tesis (en Web of Science).

- Aplicación de un método de cálculo determinístico y otro probabilístico (técnica de Montecarlo), con un enfoque novedoso, con el fin de determinar cuándo y cómo es posible alcanzar la paridad de red fotovoltaica. Los resultados alcanzados demuestran que, en muchos de los casos estudiados, la paridad de red ya se ha alcanzado en España, por lo que se trata de una tecnología madura que no precisa de políticas retributivas especiales. Se estudió el efecto de los costes de la financiación en la rentabilidad de la instalación en función del tamaño de la misma, evaluando la tasa de éxito de la inversión mediante el método de Montecarlo. Este trabajo permitió publicar el artículo: C. Sarasa-Maestro, R. Dufo-López, J. Bernal-Agustín, Evaluating the Effect of Financing Costs on PV Grid Parity by Applying a Probabilistic Methodology, Appl. Sci. 9 (2019) 425.
  La revista Applied Sciences está indexada en JCR, siendo Q2 en una categoría en el año 2018.

6.2 Trabajos futuros

Como trabajos futuros se plantean:

- Considerar las distintas normativas de las instalaciones de autoconsumo que incluyen baterías en España y en otros países, evaluando la rentabilidad de las distintas alternativas aplicando la técnica de Montecarlo.
- Evaluar la posible sustitución de las baterías de plomo-ácido, que habitualmente se instalan en sistemas aislados de la red, por baterías de litio. Para ello se plantea considerar, inicialmente, únicamente el envejecimiento debido al ciclado ("*cycle ageing*"), determinando el coste que debería tener la energía ciclada en las baterías de litio (€/$kWh_{ciclado}$) para que sean competitivas económicamente con las de plomo-ácido.
- Ampliar el estudio anterior considerando modelos de vida de baterías que incluyan el envejecimiento por ciclado y el envejecimiento debido a la corrosión cuando la corriente es baja (envejecimiento por calendario, "*calendar ageing*"), evaluando la posible competitividad, presente o futura, de las baterías de litio frente a las de plomo-ácido.

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Photovoltaic remuneration policies in the European Union

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HIGHLIGHTS

► This work shows the EU positioning on development of photovoltaic (PV) systems.
► The installed power and the internal rate of return have been used as reference.
► The existing programs in relation to pay and incentives have been reviewed.

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ABSTRACT

The purpose of this paper is to study the development of photovoltaic (PV) systems in some countries of the European Union (EU). We establish the stage of development of each country, their short- and long-term degree of compliance and the trends of international investors favouring one market or another. EU countries employ four major types of programs to encourage PV use: (1) feed in tariffs (FIT), (2) green certificates with a quota system, (3) investment and tax incentives, and (4) bids on the quota system. The FIT is the most widely used program to create incentives for the use of PV systems. During the past two years, PV tariffs have been reduced in many European countries. Investments in PV are still attractive, in some cases even overly generous with respect to the financial landscape in the world.

This paper shows, for each country, the type of incentive and the trends in and forecast for installed capacity and calculates the internal rate of return (IRR) for investment in grid-connected PV systems.

1. Introduction

Photovoltaic (PV) installation has seen remarkable growth since 2005, especially in the European Union (EU). The general philosophy is to encourage the installation of PV solar energy by promoting private, profitable investment in a particular PV plant. This remuneration policy is the key to the development and future of the PV industry, for both the private investors and governments involved. Despite having lower solar radiation than other countries in Europe, Germany has led the market since 2004 and positioned itself as a leader in the industry.

The program most often used to encourage PV installations is FIT, a fixed-price contract for a specified period of time with procedural operating conditions. Recent experience indicates that FIT is the most effective reward system to increase the development of various power generation systems (Couture and Gagnon, 2010). FIT can be combined with a premium on the price of energy in the spot market. The amount of the premium is related to the cost or value of the energy generated.

This remuneration system may count the total kW h produced, including consumption (gross FIT), or the net kW h (net metering). Gross FIT implies that all the energy produced by the PV system is remunerated and that the energy consumed by the system (for example, the energy used by the house in a home PV system) is bought to the electrical grid at the price of the electricity. Net metering, on the other hand, grants remuneration for only the net energy injected to the electrical grid (the energy produced by PV minus the energy consumed by the system). Tariff rates may vary depending on plant size, technology, and other factors, and their value may decrease over time.

Another program used by some countries is the green certificates with quota system. Under it, the government requires producers, distributors or consumers to maintain a certain quota of renewable energy in their overall energy consumption. The price of energy is set by the actors involved in the program. The quota system is generally known as a quota obligation or Renewable Portfolio Standard (RPS) in the United States. Green certificates are the primary mechanism used to implement this system.

Government tax incentives and support for investment are also used to encourage the use of PV systems. A set of measures eases access to credit and reduces the tax burden for the installation of PV systems. The cost of capital is seen as the main

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barrier to the development of the PV industry. Different measures act as investment support, such as grants and loans, or tax incentives, such as tax credits, reduced taxes, and accelerated depreciation. Incentive programs usually use a combination of these methods.

The fourth program employed in some countries is the bid to quota system, in which the government holds public auctions for certain projects to produce electricity. Each producer has a project, and the winning bidder is then paid for it.

The following sections of this article show the current development of and forecast for several European countries that have opted to promote PV energy. The forecast was produced through comprehensive, extensive data collection and market research based on a highly representative sample of the PV industry, national associations, and energy agencies. Through the cross-checking of data and the consolidation of complementary market projection methods, two scenarios for the future development of the PV industry are proposed: the government sales policy-driven and the moderate scenarios. The government sales policy-driven scenario refers to the potential for installing PV created by each regulatory framework. This potential depends solely on the power ceiling in each country. Without a power ceiling, it is estimated that the maximum value of the power will be installed. The moderate scenario refers to the power expected to be installed annually in each country, depending on the sector's capacity, the number of companies, and other factors. The differences between the moderate scenarios and governmental forecast scenarios arise from the market response to the different incentives offered by countries.

The mechanisms of financial support given to different sources of power generation in different countries (Badcock and Lenzen, 2010) have strongly encouraged the development of solar energy in particular. Consequently, the past economic boom and government guarantees have increased some financial groups' interest in investing in PV generation (Szabó et al., 2010) when the profitability ratios, financial conditions, and quantification of risk are clearly defined. Investors have become a fundamental part of the energy policy framework in all countries (Bürer and Wüstenhagen, 2009), especially in the current situation in which access to financing is limited.

This article explores how the different methods of FIT implemented in different EU countries balance the market and PV industry.

Table 1 shows the internal rate of revenue (IRR) and other relevant data for different EU countries. The data displayed in Table 1 are discussed and analysed in the following sections.

The IRR is calculated using Eq. (1),

$$NPV = \sum_{t=1}^{n} \frac{F_t}{(1+IRR)^t} - I = 0 \quad (1)$$

where, F_t is the cash flow during the year t, n is the number of years of the investment, and I is the initial investment (€).

The annual (per period) cash flow is the income less the maintenance cost after taxes (considered a standard tax in a limited society that does not have another kind of business). Numerical analysis was used to obtain IRRs that fit Eq. (1). The IRR results assume a typical installation of 120 kWp (peak power) rooftop PV and 100 kW of nominal power which costs 2.0 €/Wp and is executed in one month, an average inflation of 2.5%, and maintenance costs of 7% of income before taxes. The lifetime of the investment is the duration of the FIT for each country. All the electricity produced by the PV system is sold to the electrical grid at FIT.

As Table 1 illustrates, the difference between IRR without loans (ninth column) and with loans (eighth column) is substantial. Loans are the most common investments in the PV industry. The interest ratio demanded by banks makes the loan payments and the fee more or less equivalent. Therefore, the project's cash flow is around zero during the loan period, but as its end approaches, all income is profit.

The results in Table 1 are based on a financing scheme for 80% of the construction costs of the PV installation and the investor bearing 20% of the installation cost. The interest rate is estimated at 6%. The time for repaying the loan is 12 years (11 years plus a 1-year grace period), and payment is calculated monthly. Thus, the calculated IRR is based on a project financing scheme typical of the PV industry.

2. Germany

Germany led the world in installed PV capacity during the first decade of the 2000s. Germany had 81% of installed capacity worldwide in 2006, 64% in 2007, 35% in 2008 and 67% in 2009 (EPIA, 2012).

The growth of the installed power in German has been driven by discounts that are not retroactive. Germany is a world leader in both the PV market and PV installed power (Frondel et al., 2010), and as a result, the German PV industry has participated in several research and development (R&D) programs.

Table 1
IRR and other relevant data in some EU countries.

Country	Specific Annual Yield[a] kW h/kWp	FIT €/kW h	Corporation Tax[b] %	VAT %	Lifetime years	Electricity Price (Europe's Energy Portal, 2012) €/kW h	IRR Loan Model %	IRR W/O Loan %
Germany	1250	0.1601	29.51	19.00	20	0.2282	10.84	8.39
Spain	1575	0.21	30.00	18.00	25	0.172	34.60	15.16
France	1275	0.2137	33.33	19.60	20	0.1215	21.00	12.49
Italy	1500	0.233	31.40	20.00	20	0.1946	37.50	16.02
Greece (Continent)	1500	0.292	25.00	19.00	20	0.1061	20.00	21.46
Greece (Islands)	1500	0.292	25.00	19.00	20	0.1061	20.00	21.46
Portugal	1500	0.32	25.00	22.00	15	0.1668	80.00	23.20
United Kingdom	975	0.19	28.00	15.00	25	0.1347	9.38	7.74
Belgium	900	Various	34.00	21.00	Various	0.1896	Various	Various
Bulgaria	1275	0.367	10.00	20.00	25	0.0865	81.66	25.41
Czech Republic	880	0.423	19.00	19.00	20	0.1455	46.52	18.34
Switzerland	1100	0.41	25.45	7.60	25	0.1897	108.59	23.03

[a] PVGIS (2012), best conditions of the country.
[b] Taxation and Customs Union (2012) taking into account the energy produced by the 100 kW PV system.

The German PV industry is forecast to grow at the rate of about 5 GW per year through 2015 (Fig. 1 policy-driven scenario), at which point it will have doubled its installed capacity from 2010. From 2005 to 2010, the annual rate of growth was about 50%, except when it exceeded 76% in 2010. Through 2010, the PV industry is predicted to see more moderate annual growth of around 20%.

In Fig. 1, the continuous line show the total accumulated PV power installed in Germany, and the bar diagram represents the sales policy driven by the government (the annual potential to install PV created by each regulatory framework). The moderate sales scenario forecasts are lower than those for the policy driven by the government, which directly influences the pay per kW h paid by the government. The German government plans to install the declared total power, but the market is expected to be more conservative, because the incentive pay is shrinking and the cost of installation is unlikely to fall proportionally, reducing profitability.

2.1. Sale of power to the electrical grid.

German regulations stipulate quarterly rates which were decreased during 2010 and 2011 and will continue to be decreased annually after 2012. There were two drops of 13% during 2010 and another in 2011. From 2011 to 2014, an annual decrease of 9% has been scheduled (Tables 2 and 3). This is a clear example of long-term programming of the industry.

In addition, new tariffs with an extraordinary revision were published in April 2012, forcing regulation on the FIT to be changed to meet the large demand from investors. The new renewable plan is shown in Table 4. Farms larger than 10 MW will no longer receive FITs.

2.2. Self-consumption

The practice of self-consumption is increasing across the European continent, especially in Germany, so the German government has regulated rates based on the percentage of PV generation relative to the electrical consumption of a building. As in the case of grid connection, the tariff will be reduced according to the date of construction and connection of the installation (Table 5).

In addition to the savings from PV energy, self-consumption creates extra cost reductions and yields an acceptable return. As shown in Table 3, several fees apply depending on the size of the facility.

2.3. Highlights

Germany is the world leader both in this market and in installed PV power. After the large reductions in tariffs in 2010, the rates will decline 9% annually from 2011 to 2014, a clear example of long-term planning. The PV solar energy investments in Germany produce an IRR of 10.8% (see Table 1) for a typical installation of a 120 kWp (peak power) rooftop PV system with 100 kW of nominal power, a funding rate of 80% and 25-year lifetime of the investment.

3. Spain

In 2004, Spain began to promote the use of PV energy through incentives (bonuses) for production. This strategy, established by the government in legislation (Royal Decree 661/2007, 2007), encouraged private developers to inject capital into the installation of PV plants. Until 2009, no distinction was made between plants on the ground and plants on roofs. The forecast for PV installation in Spain is shown in Fig. 2.

Self-consumption is not permitted in Spain, and all the energy produced is sold to the grid. The government is working on a royal decree that will legalize self-consumption and create a system to rapidly certify such low-power plants.

Since 1998, Spain has developed one of the best public promotional campaigns for the production of renewable energy, particularly wind power (Del Río, 2008). The aforementioned paper describes the evolution of the various royal decrees concerning renewable energy and the consequent changes in the rate and power of consumption.

As shown in Fig. 2, Spain experienced unsustainable growth in its installed capacity of PV energy in 2008. With the start of the

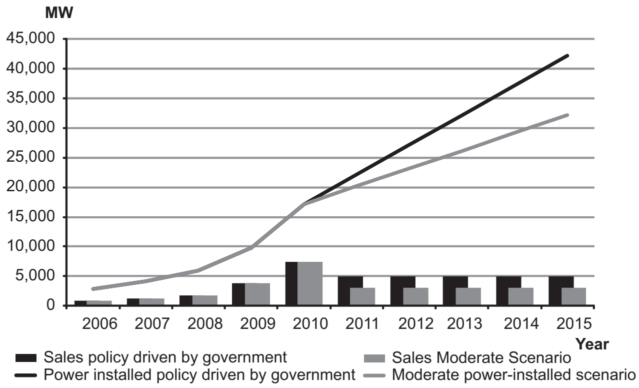

Fig. 1. Growth and forecast of sales and PV power installed in Germany (EPIA, 2012).

Table 3
Tariffs (c€/kW h) for installation on the ground (Germany Federal Ministry of Environment, 2011).

	January 2010	July 2010	October 2010	January 2011	January 2012	January 2013	January 2014
Industrial	28.43	26.15	25.37	22.07	20.08	18.27	16.63
Others	28.43	25.02	24.26	21.11	19.21	17.48	15.97
Farms	28.43	–	–	–	–	–	–

Table 2
Tariffs (c€/kW h) for installation on a roof (Germany Federal Ministry of Environment, 2011).

	January 2010	July 2010	October 2010	January 2011	January 2012	January 2013	January 2014
$P>1000$ kW	29.37	25.55	24.79	21.56	19.62	17.85	16.24
$P>100$ kW	35.23	30.65	29.73	25.86	23.53	21.41	19.48
$P>30$ kW	37.23	32.39	31.42	27.33	24.87	22.63	20.6
$P<30$ kW	39.14	34.05	33.03	28.74	26.15	23.8	21.66

Table 4
Tariffs (c€/kW h) for installation on roof and ground (Germany Federal Ministry of Environment, 2012).

Roof mount	1/4/2012	1/5/2012	1/6/2012	1/7/2012	1/8/2012	1/9/2012	1/10/2012
$P<10$ MW	13.5	13.37	13.23	13.1	13.97	12.84	12.71
$P<1$ MW	16.5	16.34	16.17	16.01	15.85	15.69	15.53
$P<40$ kW	18.5	18.32	18.13	17.95	17.77	17.59	17.42
$P<10$ kW	19.5	19.31	19.11	18.92	18.73	18.54	18.36
GROUND MOUNT	1/1/2010	1/7/2010	1/10/2010	1/1/2011	1/1/2012	1/1/2013	1/1/2014
Farms	13.5	13.37	13.23	13.1	13.97	12.84	12.71

Table 5
Rates of self-consumption of electricity in c€/kW h. Values not additive to those in Table 4 (Germany Federal Ministry of Environment, 2011).

Date	Buildings with 100–500 kW installed		Buildings with more than 30 kW installed		Buildings with up to 30 kW installed	
	30% of energy consumed	More than 30%	30% of energy consumed	More than 30%	30% of energy consumed	More than 30%
January 2010	0	0	0	0	22.76	22.76
July 2010	14.27	18.65	16.01	20.39	17.67	22.05
October 2010	13.35	17.73	15.04	19.42	16.65	21.03
January 2011	9.48	13.86	10.95	15.33	12.36	16.74
January 2012	8.63	12.61	9.96	13.95	11.25	15.23
January 2013	7.85	11.48	9.06	12.69	10.24	13.86
January 2014	7.14	10.44	8.25	11.55	9.31	12.61

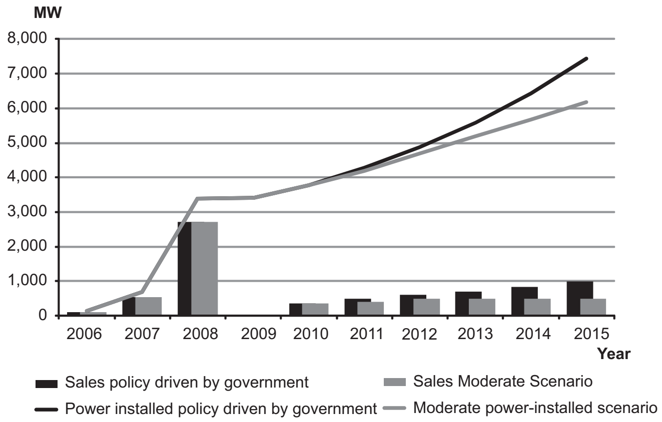

Fig. 2. Evolution and forecast of installed capacity in Spain (EPIA, 2012).

economic crisis, power consumption decreased, which has caused short-term increases in the deficit. For this and other reasons, the government regulated the growth of installed power in Spain by a royal decree (RD) 1578/2008 (Royal Decree 1578/2008, 2008) published September 29, 2008, establishing a consolidated growth plan of 500 MW per year and setting a quota of power (maximum power to be installed in a given period) by type, consisting of a power base and additional power.

The power base established for the first year calls for installation of 267 MW of type I (roof) and 133 MW of type II (ground) PV systems. The power base for the second year and each subsequent year is calculated taking as reference the power base of the demand for each technology in the previous year and increasing or decreasing it by the same accumulated percentage rate as the remuneration decreased or increased during the previous year. A quota of additional power for type II systems of 100 MW in 2009 and 60 MW in 2010 was granted, creating a total power of 500 MW for those two years.

Under RD 1578/2008, the regulated tariffs for facilities that use solar radiation and PV technology as their primary source energy set by the 2009 register of pre-assignment were:

- Type I (top, 267 MW):
  - Subtype I.1 (<20 kW), 34.00 c€/kW h
  - Subtype I.2 (>20 kW and <1 MW), 32.00 c€/kW h
- Type II (ground, 133 MW): 32.00 c€/kW h

The regulatory formula for premium on the required power is calculated using Eqs. (2) and (3).

$$\text{If } P \geq 0.75 \times P_0, \text{ then } : T_n = T_{n-1}[(1-A) \times (P_0 - P)/(0.25 \times P_0) + A] \tag{2}$$

$$\text{If } P < 0.75 \times P_0, \text{ then } : T_n = T_{n-1} \tag{3}$$

where,

P is the power in the pre-recorded call $n-1$,
P_0 is the power quota for the call $n-1$,
T_{n-1} is the rate for pre-registered facilities associated with the call $n-1$,
T_n is the rate for pre-registered facilities associated with the call n,
A is the factor $0.9^{1/m}$, and
m is the number of annual calls.

Eqs. (2) and (3) establish a FIT, or a so-called self-regulatory fee (Del Río and Gual, 2007; Couture and Gagnon, 2010). If this equation shows that demand is higher than 75% of the available power, Eq. (2) will be applied; otherwise the fee will stay unchanged (Eq. (3)).

Recent studies have concluded that FIT is more effective for solar energy produced by PV technology than other forms of compensation (Lesser and Su, 2008). The FIT should be calculated

Table 6
Installed capacity in Spain and the price payable per kW h.

Call number	Installed capacity (MW)			Price payable (€/kW h)		
	I.1	I.2	II	I.1	I.2	II
1st/2009	6.675	60.075	90.552	0.34	0.32	0.32
2nd/2009	6.675	60.075	94.552	0.34	0.32	0.3071893
3th/2009	6.675	60.075	89.512	0.34	0.32	0.2991125
4th/2009	6.675	60.075	85.615	0.34	0.32	0.290857
1st/2010	6.016	62.522	50.894	0.34	0.311665	0.281045
2nd/2010	6.653	61.439	51.339	0.334652	0.303099	0.273178
3th/2010	6.675	61.64	52.105	0.330597	0.2952	0.265509
4th/2010	6.537	60.401	52.288	0.321967	0.286844	0.258602
1th/2011	7.09	67.185	40.869	0.313542	0.278887	0.251714

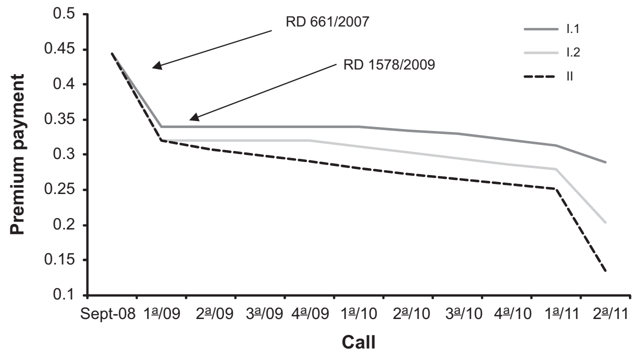

Fig. 3. Evolution of the tariff according to call (RD 1578).

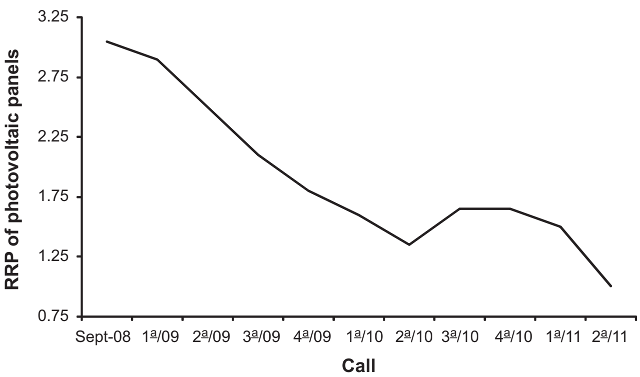

Fig. 4. Evolution of the price of photovoltaic modules.

based on different factors (energy prices, ability to pay, period and horizons). Applied to the case of Spain, this finding implies that, if demand for the installation of power rises above the installation ceilings, the rate automatically decreases, establishing more economically stringent conditions for the next call for renewable energy projects. Therefore, the market is conditioned by the FIT system, which should support the sustainability of the sector (Del Río and Gual, 2007; Couture and Gagnon, 2010).

The development of the sector in 2009 and 2010 caused the rate of PV installation to decline, as shown in Table 6.

Depending on the call in which the project is registered, the premium payable will differ. Fig. 3 shows the evolution of the tariff according to call.

The first step was the transition from RD 661/2007 (2007) to RD 1578/2008 (2008), when the sector experienced a five-month slowdown in the absence of a regulatory system. The issuance of the first call in 2009 with its new rates caused a decline in profitability, because the drop rate was 28%, and construction costs and materials stayed constant. At that time, the retail price (RP) of PV panels also began to decline (Fig. 4).

Since 2009, the manufacturing and installation prices have fallen to match the profitability influenced by RD 661/2007. Even in roof installations, profitability rose due to the declining price of PV panels, which led to an increase in applications for roof installations and therefore lowered the rate of PV installation, as shown in Table 6. The lowest price point of a panel (April 2010) is obviously the point of maximum profitability.

3.1. Extraordinary rate reductions

In November 2010, the Spanish government drew up Royal Decree 14/2010 (2010) to regulate the rates for new PV installations. Remarkably, it lowered rates. This drop led to extraordinary reductions in the rate for the first call of PV energy before allocation from the RD came into effect.

In the first call for registration for pre-term assignment of remuneration, which is filed before the RD comes into effect, the rates of PV systems are calculated from the values resulting from the application of the methodology set out in RD 1578/2008 (see Eqs. (2) and (3), the results of which are shown in Table 5), multiplied by the following factors:

Type I.1 Installations: 0.95 → Reduction of 5%
Type I.2 Installations: 0.75 → Reduction of 25%
Type II Installations: 0.55 → Reduction of 45%

These percentage reductions in the rates shall not be taken into account for calculating power quotas for next year.

Royal Decree 14/2010 (2010) also establishes a limitation on hours of sunshine that may be used by each type of facility in different areas of Spain (Table 7).

The royal directive also placed an extraordinary limitation on the solar yield rate through 2013 for the facilities covered by RD 661/2007 (2007). On the other hand, their operation was extended to 28 years. The maximum production peak hours are shown in Table 8.

This variation decreases the IRR of a 25-year installation by 1%. For an installation with 100 kW of nominal power, 120 kWp (peak power), a market price of 700,000 € and 80% financing, the IRR decreases from 12.58% to 11.74% because of a 20% reduction in the production environment of facilities covered by RD 661/2007. This variation requires reinvestment during these years because the cash flow might not be enough to repay the loan as scheduled.

Table 7
Limitation on hours of sunshine used by plants in different areas of Spain.

Technology	Specific Annual Yield				
	Zone I	Zone II	Zone III	Zone IV	Zone V
Installation fix	1232	1362	1492	1632	1753
Installation with 1 axis tracker	1602	1770	1940	2122	2279
Installation with 2 axis tracker	1664	1838	2015	2204	2367

Table 8
Limit on hours of solar production by 2013.

	Specific Annual Yield
Installation fixed	1250
Installation with 1 axis tracker	1644
Installation with 2 axis tracker	1707

Finally, another cut has been announced: Facilities may be paid with the rate regulated for only 25 years, not 40 years as set out in RD 661/2007 (2007). This decision was made in Royal Decree 1/2012 (2012) in January 2012 when the government announced the cessation of all calls for the registration of renewable energy. At the moment, the renewable energy industry in Spain has been halted, with all the consequences that result from such a lack of action. It is unknown when this royal decree will be lifted.

3.2. Highlights

In Spain, the previously strong commitment to PV solar energy is decreasing, and an increase in energy from nuclear sources is being considered. Declining electricity consumption has also caused the growing shortfall in revenue. The European community continues to push Spain to take measures to ensure stability, including regulating the renewable energy sector, which experienced uncontrolled and unsustainable growth exacerbated by the economic boom in the first decade of the 21st century.

Before the general halt in January 2012, PV solar energy investments in Spain produced an IRR of 34% for a typical installation with 120 kWp rooftop power, 100 kW nominal power and a funding rate of 80% (Table 1). The cessation of all renewable calls in 2012 has halted the PV industry in Spain.

4. France

France has a culture of great technical efficiency, but solar energy has not been highly developed, in part because of the high returns offered by such neighbouring countries as Germany, Italy and Spain. Fig. 5 shows the development of installed capacity in France. Also demonstrated in Fig. 5, the growth of the installed capacity of PV power is expected to increase its share of power in the country by 10% annually. Installed capacity is projected to reach 3 GW by 2020.

The tariff France instituted in 2009 is composed of the cost of generation plus a bonus (Solangi et al., 2011), depending on if the installation follows design patterns that address distributed generation.

The facilities will be installed mainly on roofs (BIPV), and the rates will be for facilities on the ground. Higher interest rates encourage facilities on islands, improving the electrification of them without having to use secondary methods and hybrid PV systems (Table 9).

The drop in rates shown in Table 9 has occurred for two reasons:

- The sudden increase of installed capacity during 2008, 2009 and 2010 when growth was approximately 200%.
- Increased electric rates for households, of which government sources suggest 5% goes to supply the PV rate.

However, the decline of 10% can still yield attractive returns.

4.1. Highlights

The current installation prices in France could produce a highly attractive IRR. Therefore, strong growth in France's installed capacity likely signals further rate cuts to adjust cost effectiveness in comparison to neighbouring countries.

PV solar energy investments in France produce an IRR of 21% for a typical installation with 120 kWp rooftop power, 100 kW nominal power and a funding rate of 80% (Table 1).

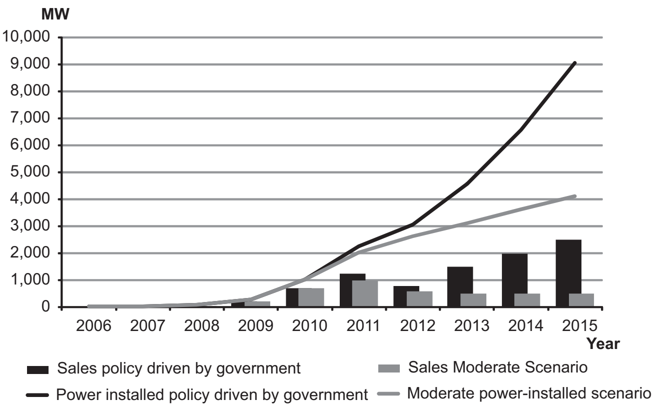

Fig. 5. Growth in installed capacity in France (EPIA, 2012).

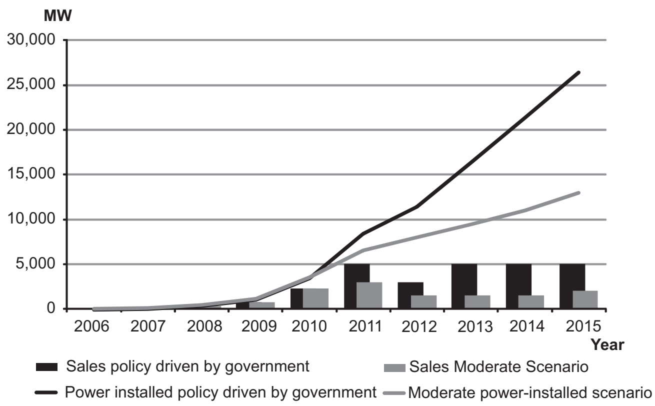

Fig. 6. Growth in installed capacity in Italy (EPIA, 2012).

Table 9
Rates of past and current PV grid feed (CRE, 2011), in €/kW h.

	Residential				Health or education building				Other buildings			Any installation
	BIPV (Building integration PV)		Simple BIPV		BIPV (Building integration PV)		Simple BIPV		BIPV (Building integration PV)	Simple BIPV		
	0–9 kWp	9–36 kWp	0–36 kWp	36–100 kWp	0–9 kWp	9–36 kWp	0–36 kWp	36–100 kWp	0–9 kWp	0–36 kWp	36–100 kWp	0–12 MWp
10/03/2011 to 30/06/2011	46	40.25	30.35	28.83	40.6	40.6	30.35	28.83	35.2	30.35	28.83	12
01/07/2011 to 30/09/2011	42.55	37.23	27.46	26.09	36.74	36.74	27.46	26.09	31.85	27.46	26.09	11.68
01/10/2011 to 31/12/2011	40.63	35.55	24.85	23.61	33.25	33.25	24.85	23.61	28.82	24.85	23.61	11.38
01/01/2012 to 31/03/2012	38.8	33.95	22.49	21.37	30.09	30.09	22.49	21.37	26.09	22.49	21.37	11.08

5. Italy

Until 2006, the installation of PV plants in Italy was unregulated. In 2006, premiums were set at approximately 0.40 €/kW h, but Spain continued to led Europe in power installed and production. Installation was promoted in northern Italy, where there was no production higher than 1300 kW h/kWp. With the industrial halt in Spain, Germany emerged as the European market leader, but Italy has posted higher yields (Fig. 6).

The installed capacity tripled in 2009 and doubled in 2010. This growth indicates increasing interest in PV investments in Italy since 2009, when the annual growth rate was 1 GW. Although no reliable figures for installed capacity in 2010 are available, we are confident that it exceeded government expectations as a new regulatory framework was introduced (Table 10). As shown in Table 10, the rate was decreased three times in 2011 with the objective to stabilize the growth of installed capacity in Italy and return to the parameters of the estimates shown in Fig. 6. The rate decreased 16% from the beginning to the end of 2011, creating an additional drop of 20% from the previous rate. Tariff reductions of approximately 25% are expected in 2012.

5.1. Highlights

Coinciding with the drop in tariffs in Spain, Italy launched a new plan to promote PV systems, with rates of 0.36 €/kW h for soil installation. This offering has drawn Spanish and European promoters to develop their PV facilities with an IRR of more than 15% in Italy. The drop in price and installation costs for PV projects in Italy yields an IRR of 37%. Given the development of pay policy in Spain, investors expect a similar cut, causing rapid growth in installed capacity in a short time (2010), which would trigger a further decline in remuneration rates (GSE, 2011).

The PV solar energy investments in Italy produce an IRR of 37% (including the 25% reduction the government will apply this year) for a typical installation with 120 kWp rooftop (peak power), 100 kW of nominal power and a funding rate of 80% (see Table 1).

6. Greece

The development of the PV market in Greece arguably did not take off until 2010 (Fig. 7), even though a FIT went into effect at the end of 2006, prompting more than 7000 requests for connection points (Papadopoulos and Karteris, 2009). The forecast for the growth of installed power is extremely moderate.

Greece has high solar radiation and the highest FIT rate in Europe, which motivated promoters to develop new projects throughout 2008. Greece has the peculiar feature of a multitude of islands, whose populations have high interest in the development of independent power generation through non-combustible sources. This situation promotes the installation of PV systems on the islands, adding an economic incentive to the FIT (Table 11).

After consultations with stakeholders and environmental organisations, the Greek Ministry of Environment published new FITs for PV installations (Art.13 Par. 1 Law No. 3468/2006) effective February 1, 2012 (Tables 12 and 13). The tariff for PV systems of up to 100 kW and for systems installed on non-interconnected islands has been reduced by 12.5% from the rate introduced in 2009. The new tariff will be further reduced by 7% every six months until August 2014.

The tariff will start at 0.328 €/kW h in February 2011 and eventually drop to 0.229 €/kW h ($P=100$ kW) in August 2014. From February 2015 on, both tariffs will continue to be gradually reduced.

Meanwhile, the tariff for rooftop PV systems up to 10 kW will be reduced by 5% every six months. It was set initially at 0.495 €/kW h and will end with a tariff of 0.383 €/kW h in 2014. At the end of September 2011, the installed capacity was 460 MW, up from 198 MW in late 2010. Greece expects to achieve its national target for installed capacity ahead of schedule.

6.1. Highlights

On the positive side, Greece has a high degree of solar radiation and one of the highest FIT rates across Europe. More than 3.5 GW of projects are waiting to be executed. Many of the projects planned for 2008 were actually installed in 2009 because of the great administrative complexity of the Greek government.

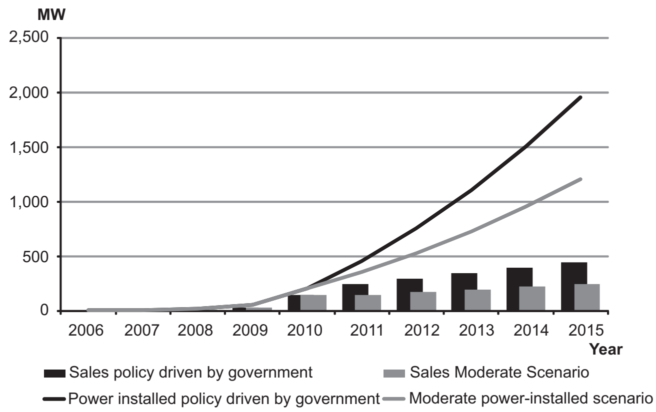

Fig. 7. Growth in installed capacity in Greece (EPIA, 2012).

Table 10
Italian PV rates from 2011 on D.M. 6/8/2010 (2010).

POWER [kW]	Tariff [€/kWh]					
	A Connected between 31/12/2010 and 30/04/2011		B Connected between 30/04/2011 and 31/08/2011		C Connected between 31/08/2011 and 31/12/2011	
	Roof	Ground	Roof	Ground	Roof	Ground
$1 \leq P \leq 3$	0.402	0.362	0.391	0.347	0.380	0.333
$3 < P \leq 20$	0.377	0.339	0.360	0.322	0.342	0.304
$20 < P \leq 200$	0.358	0.321	0.341	0.309	0.323	0.285
$200 < P \leq 1000$	0.355	0.314	0.335	0.303	0.314	0.266
$1000 < P \leq 5000$	0.351	0.313	0.327	0.289	0.302	0.264
$P > 5000$	0.333	0.297	0.311	0.275	0.287	0.251

Table 11
Greek PV rates from 2010 to 2011 (RAE Law No. 3468/2006, 2006), in €/kW h.

	Up to 08/2010		From 8/2010 to 02/2011		From 02/2011 to 08/2011	
	Roof	Ground	Roof	Ground	Roof	Ground
Continent						
$P \leq 20$	0.45	0.45	0.4185	0.4185	0.389205	0.389205
$P \leq 100$	0.45	0.45	0.4185	0.4185	0.389205	0.389205
$P \geq 100$	0.4	0.4	0.372	0.372	0.34596	0.34596
Islands						
$P \leq 20$	0.5	0.5	0.465	0.465	0.43245	0.43245
$P \leq 100$	0.5	0.5	0.465	0.465	0.43245	0.43245
$P \geq 100$	0.45	0.4	0.4185	0.372	0.389205	0.34596

Table 12
PV rates from August 2012 to 2014 for ground-mounted and roof-top installations.

	August 2012			February 2013			August 2013			February 2014			August 2014		
Power (kW)	> 100	< 100	< 10	> 100	< 100	< 10	> 100	< 100	< 10	> 100	< 100	< 10	> 100	< 100	< 10
Rate (c€/kW h)	0.180	0.225	0.250	0.172	0.215	0.239	0.164	0.205	0.228	0.157	0.196	0.218	0.150	0.187	0.208
Term (Years)	20		25	20		25	20		25	20		25	20		25

Table 13
PV rates from February 2012 for ground-mounted and roof-top installations.

	Power (kW)		
	> 100 kW	< 100 kW	< 10 kW
Rate (c€/kW h)	0.292	0.328	0.495
Term (Years)	20	20	25

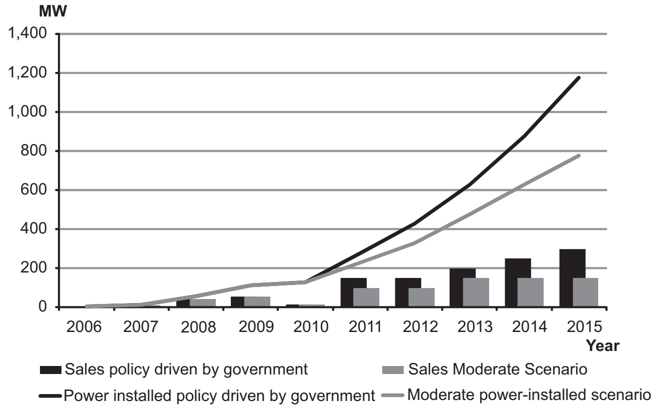

Fig. 8. Growth of installed power in Portugal (EPIA, 2012).

Table 14
Rates PV from 2009 onwards in Portugal, in €/kW h.

	Roof	Ground
$P \leq 5$ kW	0.42	0.42
$P > 5$ kW	0.32	0.32

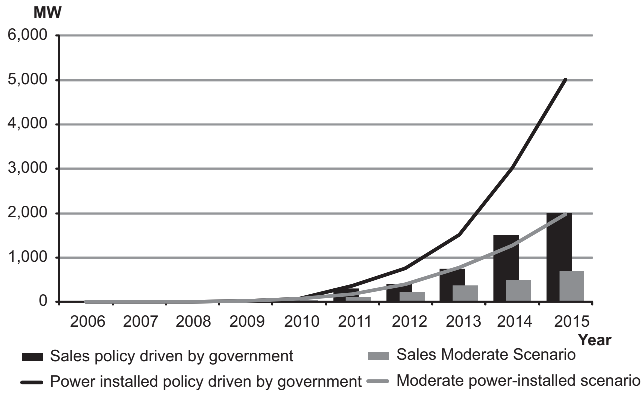

Fig. 9. Growth of installed capacity in the UK (EPIA, 2012).

Table 15
Rates of PV (in pence/kW h) in the UK from December 2011.

PV Size system	Up to 12/12/11	From 12/12/11
≤ 4 kW (New building)	37.8	21
≤ 4 kW (Renovated building)	43.3	21
4–10 kW	37.8	16.8
10–50 kW	32.9	15.2
50–150 kW	19	12.9
150–250 kW	15	12.9
250 kW–5 MW	8.5	8.5
Stand-alone	8.5	8.5

The situation of Greece in 2010 leads us to predict that the leadership positions in the country have been established.

PV solar energy investments in this country produce an IRR of 20% for a typical installation with 120 kWp rooftop (peak power), 100 kW of nominal power and a funding rate of 80% (Table 1).

7. Portugal

PV power was first installed in Portugal in 2007 and 2008, and subsequent growth has been extremely mild (Fig. 8).

As shown in Fig. 8, despite the growth experienced in 2008, the rate of installation is low compared to other EU countries. Installation has been regulated by a FIT since 2009 (Decree Law No. 118/2010, 2010), and rates have not changed since then (see Table 14).

7.1. Highlights

Despite Portugal's high solar radiation, the growth of the country's PV energy industry has been cautious in recent years, mainly large parks and some micro-generation facilities.

PV solar energy investments in Portugal produce an IRR of 80% for a typical installation with 120 kWp rooftop power, 100 kW nominal power and a funding rate of 80% (Table 1).

8. United Kingdom

In the UK, installed PV capacity in 2011 was negligible. Previously, this source of energy had not been exploited because of the low solar radiation received in the UK, but a growing commitment to protecting the environment and lowering CO_2 emissions has caused an increase in renewable energy programs.

The PV strategy in the UK will be micro-generation, which best meets the needs of the country's electrical grid (Keirstead, 2007). The current UK energy policy is designed to achieve four goals: reduce emissions of pollutants, maintain a reliable energy supply system (quality service), create competitive new markets and ensure the supply of heat. At the same time the debate about nuclear energy has been renewed (nuclear currently supplies 20% of the UK's energy).

The evolution of the UK's PV installed capacity is shown in Fig. 9.

As shown in Fig. 9, the UK installed the equivalent of the power installed in Spain through quarterly calls by 2010. The rate of development is quite ambitious, with the pace of growth around 100%.

The tariff rates were set in April 2010 and will continue for 25 years. In the 26th year, the amount received by the new systems will decrease at a rate of 8.5%. Rates were calculated so that an individual receives a 5% to 8% return over the initial investment, depending on the size of the facility.

On October 31, 2011, new cuts on the FIT were introduced, resulting in a revolution in the industry. Table 15 presents the PV rates through 2013 (DECC, 2011), when they will be reviewed.

Premiums are paid for each unit of electricity even when used on the residential or commercial property that generated the energy. Any excess electricity can be injected into the network in return for receive an extra 3 p/kW h.

8.1. Highlights

After years of reflection on implementing a financial incentive plan for PV solar power sales to the grid, the British government finally decided to follow other EU countries in doing so, despite the counter-arguments presented by opponents. This move is expected to not only achieve the set environmental goals but also to strengthen this sector as a means of overcoming the economic crisis.

PV solar energy investments in the UK produce an IRR of 9% for a typical installation with 120 kWp rooftop power, 100 kW nominal power and a funding rate of 80% (Table 1). However, if the savings produced by direct consumption of the PV system are estimated, then the IRR is higher, depending of the level of consumption.

9. Belgium

Despite a 450% increase of installed capacity in Belgium in 2007, the total PV power did not significantly increase through 2009 (Fig. 10).

Different methods produced the 406% increase of installed capacity in 2009 and 450% in 2007. The 2007 growth was fuelled by grants and returns to the taxpayer owners of facilities. Since then, the market has been regulated through green bonds.

Tariffs (EREC, 2010) are paid by green bonds, which are set by zones:

- Wallonia: Minimum of 65 € per green bonus, maximum of 100 €, and market price of 90 €. The green bonds production is paid according to the installed capacity: less than 5 kW, 7 bonus/MWh; between 5 kW and 7 kW, 5 bonus/MW h; more than 7 kW, 1 bonus/MW h.
- Brussels: Minimum of 100 € per green bonus, maximum of 150 €, and no market price. The production green bonds are paid according to the surface area of the installed PV panels: less than 20 m^2, 7.28 bonus/MW h; between 20 m^2 and 60 m^2, 5.46 bonus/MW h; more than 60 m^2, 3.64 bonus/MW h.

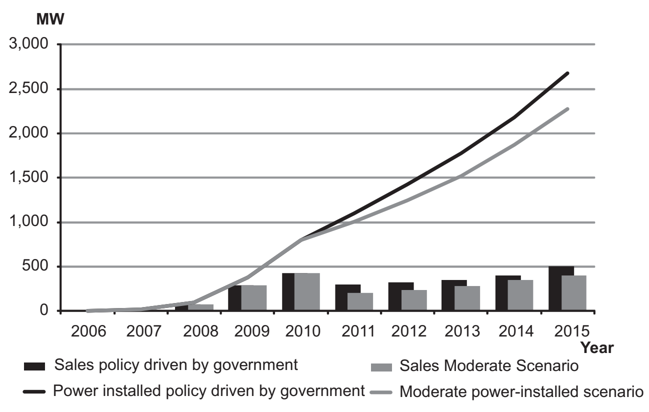

Fig. 10. Growth of installed power in Belgium (EPIA, 2012).

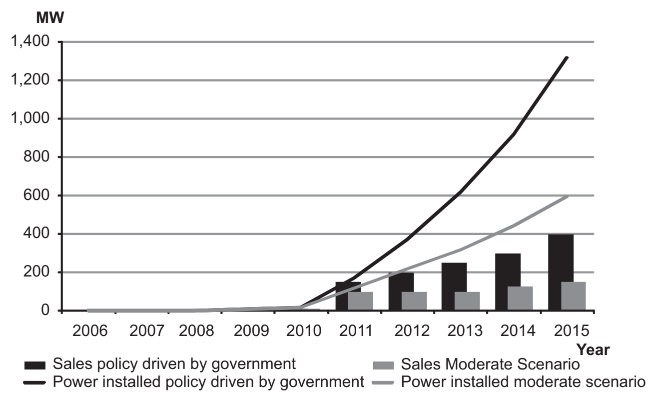

Fig. 11. Growth of installed capacity in Bulgaria (EPIA, 2012).

- Flanders Zone: Minimum of 45 € per green bonus, maximum of 125 €, and 108 € market price. The production green bonds are paid according to the surface are of the installed PV panels, which pays 1 bonus/MW h.

In all other areas of Belgium, the price is set at 150 €/MW h.

9.1. Highlights

The green bonus system creates a secondary market with a direct impact on companies that emit pollutants into the atmosphere, obligating them to compensate for the pollution by buying and selling green bonds or installing renewable-energy plants. Thus, the cost of premiums is borne directly by polluting energy generators. This remuneration policy is very well accepted by citizens who do not have to absorb the costs in the electricity tariff.

Calculations of the solar project's IRR vary according to the area of operation within Belgium.

10. Bulgaria

The Bulgarian government, like those in neighbouring countries, has established the goal to achieve a specific growth in percentage of energy generated from renewable sources (Dusonchet and Telaretti, 2010). Bulgaria initially aimed for 11% of the energy consumed by the country to be from PV sources by 2011. To reach that level, though, the market will have to take off in coming years, because the country had virtually no installed capacity until 2009 (Fig. 11).

As noted in Fig. 11, installed capacity has risen moderately since 2009.

Bulgaria's level of solar radiation is similar to that of Spain, so an equal FIT could produce similar profitability (Bulgarian Ministry of Economy, Energy and Tourism, 2009). One differentiation is made between the sizes of the installed capacity, as follows:

$P \leq 5\ \text{kW} \rightarrow 0.40\ €/\text{kW h}$

$P > 5\ \text{kW} \rightarrow 0.367€/\text{kW h}$

10.1. Highlights

The governmental influence exercised through the return of investment offered is hindered by the uncertainty that exists in countries recently admitted to the EU. Bulgaria's lack of experience in large investments is one reason why investors have not embarked on major projects there. As we can see in Fig. 11, the market is responding cautiously to the government's call for renewable energy projects.

PV solar energy investments in Bulgaria produce an IRR of 81% for a typical installation with 120 kWp rooftop power, 100 kW nominal power and a funding rate of 80% (Table 1).

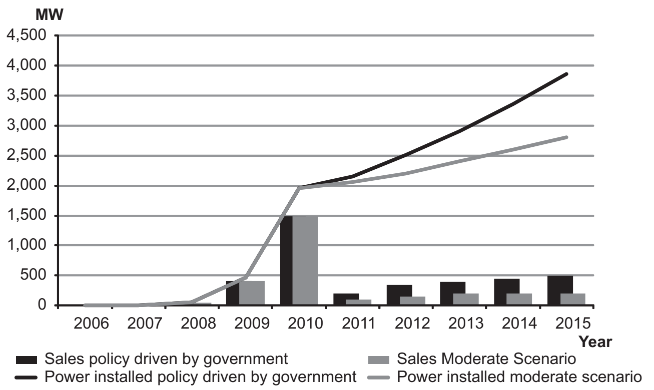

Fig. 12. Growth of installed capacity in the Czech Republic (EPIA, 2012).

11. Czech Republic

The growth in the Czech Republic is a clear legacy of the exodus of investors to new EU countries (Fig. 12).

As shown in Fig. 12, the increase in installed capacity in 2010 was out of control, forcing market regulation and rate adjustments. Consequently, growth has moderated, becoming approximately equal to that in Spain.

The Czech Republic rates are as follows (Energy Regulatory Office, 2010):

$P \leq 30\ \ \text{kW} \rightarrow 0.47€/\text{kW h}$

$P > 30\ \text{kW} \rightarrow 0.423€/\text{kW h}$

In late 2010, the Czech Senate confirmed the adoption of a retroactive amendment to the renewable energy policy. The amendment stipulates that, over the next three years, installations of 30 kW installed in 2009 and 2010 will have to pay a 26% tax on their profits. The PV industry strenuously opposes this decision. Retroactive taxation violates the conditions guaranteed to the operators of solar power plants already connected in 2009 and 2010. Current law ensures the fixed FIT during those years, but a retroactive 26% excise tax reduces the IRR guaranteed by the FIT, substantially breaking with the legitimate expectations of the operators of solar power plants.

11.1. Highlights

Governments sometimes deliberately impose retroactive taxation to halt development in certain economic sectors and thus slow them during financial crises, such as the one we live in today. Sometimes an investment's potential return becomes unattractive but still offers tax benefits for investing in a certain type of energy source.

PV solar energy investments in the Czech Republic produce an IRR of 46% for a typical installation with 120 kWp rooftop power, 100 kW nominal power and a funding rate of 80% (Table 1).

12. Switzerland

A major goal of energy policies in Switzerland is to increase the proportion of electricity generated from renewable sources, including PV, to 30% of total energy generated in the country, an increase of 5400 GW h, by 2030. The introduction of tariffs for the sale of energy to the grid in 2011 was part of this overall effort. In 2007, approximately 55% of total electricity production in Switzerland came from renewable sources. Hydropower was the largest contributor, with a 96% market share.

In 2007, the Swiss Parliament approved the Electricity Supply Act (Swedish Energy Agency [SEA], 2007) to create the legal basis for a competitive electricity market and the preconditions for ensuring energy security. The law introduces third-party access and gives an independent regulator the freedom to choose a provider for eligible customers during a transition period of five years. The law also establishes a FIT to support the generation of 5 TW h from renewable energy sources by 2030, including up 2 TW h of large hydro and the remainder from wind, biomass, small hydro, and solar and geothermal energy. PV solar energy in

Switzerland is progressing very slowly but is set for a successful future. The potential for long-term national renewable energy shows promising prospects for electricity and heat.

PV solar energy investments in Switzerland produce an IRR of 108% for a typical installation with 120 kWp rooftop power, 100 kW nominal power and a funding rate of 80% (Table 1).

13. Determining the best policy

The data in Table 1 show that it is possible to determine which policy is most suitable for PV applications. A high IRR indicates the best option for investors, although other aspects must be considered as well, because the required initial conditions could make other options more attractive, even those with lower IRR.

Most of the countries studied in this paper have used a similar formula to build the PV industry: the FIT. The system exhibits small differences among countries, but the basic remuneration is the same; the only changes are the conditions or means of payments. While, as we can see, the IRR varies among countries, these variations are caused by the risks in each country. High-risk countries must stimulate greater interest from the investors by offering more benefits through the FIT.

The main indicator for regulating the FIT is the IRR of a project, which is around 17.5% without a loan and around 36% with a loan (Table 1). We can conclude, taking the average of our results, that an investor interest can reach an IRR of 17.5% without a loan and 36% with loan (excluding the rare case of Switzerland). The governments can modify the FIT when the IRR is higher. The IRR with a loan are much higher than the IRR without a loan (Table 1) because a loan at a relatively low interest rate (6%) favours the IRR. The IRR with a loan assumes that the project has a financing scheme typical of the PV industry.

Considering the IRR, the policies of Switzerland, Bulgaria, and Portugal are the most attractive to investors in PV plants. In Switzerland, the high IRR is due to the high FIT, but this level of a FIT is unfeasible in other countries amid the current economic crisis. Thus, Switzerland's situation is not comparable to those of other countries and should not be considered as a valid alternative to other European countries where the trend is to reduce or eliminate the FIT. Therefore, Bulgaria and Portugal's policies should be considered as examples of policies that are more advantageous for an investor in PV. In some cases, a higher IRR is used to generate a pull factor for international investors in countries where the risk is high.

14. Conclusion

Now that we have examined EU countries' different rates and the expected evolution of this industry, we will analyse the current incentives for PV energy in European countries. Countries use four major pay and incentive programs: (a) FIT, (b) green certificates with quota systems, (c) tax support and incentives for investment, and (d) bid to quota system.

(a). The FIT is the most widely used incentive program. Some countries have proven that FITs encourage the development of the PV sector. The major countries in Europe that have implemented this strategy are Germany, Austria, the Czech Republic, Spain, France, Holland, Italy, Portugal, and Switzerland. The declines in the rates experienced by the investors in various countries are not reasons to end doing such installations; the market, though, is often more favourable for one country than another.

A declining FIT reaches minimum value when all the factors involved yield an IRR between 15% and 20%. When the IRR rises over 20%, governments decrease the FIT. FIT programs focus on manufacturing and installation costs, but it is extremely difficult to forecast the market trends, because all the countries are interacting with each other simultaneously.

Table 1 shows that some investments stay attractive at all times and in some cases are overly generous given the financial landscape in the world. For this reason, the pressure of the financial crisis can create retroactive lows. These retroactive declines can dampen confidence in a nation but never sink the initial claims of the investor, maintaining an acceptable return (far above any investment with risk-free return systems). Spain awaits on the courts to decide the legality of its retroactive application of limitations on the solar yield of PV production. Countries such as Spain and the Czech Republic can see confidence in them as a nation diminished, increasing their risk level for investors.

(b). Green certificates with quota systems are utilized in Belgium, Poland, the UK and Romania. This remuneration policy is well accepted by citizens who do not want absorb costs in the electricity tariff.

(c). All EU countries support investments with fiscal incentives. These tax benefits may increase the return on investments, depending upon the configuration of the corporation that owns the PV installation and on the rules and laws of each country. In the EU, Switzerland is most likely to offer tax benefits for all businesses.

(d). The contract with a quota system program is used for major projects in France. Previous experiences with this mechanism in other countries were not successful due to high transaction costs and long waiting periods. The UK and Ireland have abandoned this system, considering it inefficient. These bidding programs have had little success in the field of PV energy. France continues to use this complex procedure but only for its large power plants.

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Grid Parity Analysis of PV Markets

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Abstract. In the following paper, the grid parity is defined as the point of which the retail price of electricity is at least the same as the cost of generation (which is a mix of different generation sources: nuclear, natural gas, coal, petroleum, hydro, wind, photovoltaic, and more). This cost is levelized though a studied formula which considers various cost parameters. The grid parity depends on the photovoltaic (PV) system cost, the interest rate, and the retail cost of the electricity, so there are some variables that when combined can help researchers understand how far a system is from achieving grid parity. This study will consider some vigorous surveys to clarify which the parameters affect the results.

Introduction

Various countries within the European Union have established a feed-in tariff (FiT) to promote and encourage the development of solar PV systems. FiTs have undergone many modifications with respect to political, economical, social, and technological (PEST) matters.

Spain introduced a FiT in 2004, but due to severe financial issues and uncertain energy policies throughout the years, Spain revoked the FiT in 2012. As the energy consumption in Spain declined, this led to a significant increase in the price of electricity, turning power generation into an increasingly attractive investment source for self-consumption [1].

Having reached the point where all of the power generated can be sold to the grid at the same price at which it is purchased, the development of the photovoltaic industry becomes guaranteed, regardless of annual irradiation received in an area. At this point, grid parity is reached.

In this paper, we study grid parity as a general definition, using Spain as our case study.

Establishing the Grid Parity Point

In [1], "Photovoltaic grid parity" is defined as the point at which PV-generated electricity is at least as cheap as the grid power. At this stage, the grid parity is considered a tipping point for the cost effectiveness of solar PV, and allows the solar PV electricity to be competitive against conventional grid suppliers.

We classify electricity costs under two categories. One is the levelized cost of electricity (LCOE); the other it is the retail price, also known as the customer cost of the electricity. Although the LCOE—which is a mix of different generation sources such as nuclear, natural gas, coal, petroleum, hydro, wind, PV, and others—is not the same as the retail electricity prices. We have used it as proxy for the total price paid by consumers, adding in as many of the realistic costs as possible. The LCOE methodology is then used to back-calculate what the required system and finance costs need to be to attain grid parity [2].

The other influential factor in grid parity is the system cost. The solar panels, structure, inverters, cables, and costs of installation compose the system cost. We will not associate the depreciation value of components as the same as the modules. Therefore, we only consider the price variation of the modules, keeping the price for the rest of the components at a fixed cost.

Pricing a PV installation

We are obligated to keep the system costs up to date, as the variations can cause significant changes in the results of the analysis. Therefore, we carried out a detailed analysis of the system costs. In the last five years, the system costs have decreased as much as 25% of their original cost [3]. This is an indication we are reaching grid parity.

In May 2013, the installed PV system cost in Europe was about 1.5€/Wp, based on a 50kW ground-mounted system connected to the grid, while the price of the European panels was about 0.8€/Wp for just a single module. Currently we cannot assume a cheaper price with Chinese panel manufacturers, due to the recent antidumping charges imposed by the European Union against Chinese panels [4].

The mounting structure varies depending on the materials used, such as hot galvanized steel or aluminum. As an example, aluminum structures are priced at 0.34€/Wp. This price can decrease as much as 50% for large-scale mounted installations.

Another key system component is the inverter. The cost of an inverter can vary, based on the accuracy of the survey. For a 1MW inverter, the market offers solutions around 0.1€/Wn. A quick market survey revealed a single inverter of 5 kW from a European manufacturer can be obtained at about 1,200€, hence at a price of 0.24€/Wn.

The total installed PV system cost includes the modules, the inverter, the support structure, the electrical panels and protections, the cables and structure anchor, as well as the engineering, the mechanical and electrical installation, and VAT (value-added tax).

Based on these findings, we can assume a worst-case scenario for a 5kW system as follows in Table 1.

Table 1. Cost of a PV system at 6,000Wp (5,000W inverter)

	PV Module Cost (€/Wp)				
	1	0.8	0.6	0.4	0.2
PV module (6kWp)	6,000	4,800	3,600	2,400	1,200
Support structure	1,700	1,700	1,700	1,700	1,700
Inverter (5000W)	1,200	1,200	1,200	1,200	1,200
Electrical panel and protections	800	800	800	800	800
Other materials (cables, anchor, and so on)	500	500	500	500	500
Mechanical installation	1,620	1,620	1,620	1,620	1,620
Electrical installation and engineering	960	960	960	960	960
TOTAL PV installed cost (€)	12,780	11,580	10,380	9,180	7,980
VAT (21%)	2,684	2,432	2,180	1,928	1,676
TOTAL PV installed cost, including taxes (€)	15,464	14,012	12,560	11,108	9,656
Total specific cost (€/Wp)	2.58	2.34	2.09	1.85	1.61
Total specific cost (€/W)	3.09	2.80	2.51	2.22	1.93

We have considered five different case studies above, from which there are four theoretical cases and one practical. The panel prices at 1€/Wp and 0.8€/Wp are scenarios from the past. Although the market could raise its panel prices, the market tendency shows a continuous price reduction, and reaches the other two theoretical scenarios shown in Table 1 at prices of 0.4€/Wp and 0.2€/Wp. The realistic situation is the current situation, where the panel price is logical at quite a considerable cost.

Levelized Cost of Electricity (LCOE)

Depending on the country and the electricity remuneration system, we can use one LCOE or others, as in the case of the US [2]. Some articles have studied different LCOE systems and formulas. but for a common market case, we have selected the method described in [5], where Eq. 1 is used to calculate the value of LCOE.

$$LCOE = (\alpha I+OM)/E. \tag{1}$$

where α is the capital recovery factor, I the initial investment, OM the operation and maintenance cost, and E the annual electricity production. The capital recovery factor is calculated using Eq. 2.

$$\alpha = r / (1-(1+r)^{-L}. \tag{2}$$

where r is the interest rate, and L the lifetime of the system.

In Spain, the process of obtaining a loan is quite complicated. The interest rates are relatively high at around 10%. A few years ago the interest rate was around 5%, but the financial problems and the retroactive changes on the PV law caused a rise in interest rates. In this study, we will consider an interest rate of 10% at the first stage, as this will be one of our variable parameters. The selected lifetime is 25 years, used for comparison with the model of the FiT and also the module's warranty. The initial investment for a 6kWp system has been shown on the Table1, considering all system losses.

We have considered an OM ratio of 10% for the energy produced. From Eq. 1 we have to introduce this parameter in euros (€), so we have considered 10% of the energy multiplied by the retail cost of the electricity, obtaining Eq. 3.

$$OM = E\cdot 0.1\cdot R_t. \tag{3}$$

where the R_t is the regulated tariff for low-power consumers who do not want to negotiate with the manufacturers. Since October 2011, the regulated tariff is 17.4 c€/kWh, including taxes [1]. E can be obtained using Eq. 4.

$$E = \text{Annual Yield}\cdot\text{Peak Power}. \tag{4}$$

Annual yield can vary, depending on the location, from 1,100kWh/kWp in the north of Spain to 1,600kWh/kWp in the south of Spain. For our case study, we set the annual yield at 1,300kWh/kWp as an average. Peak power, as mentioned before, is 6kWp.

Sensitivity Analysis of the Variables

Introducing all the parameters previously defined and fixing the regulated tariff at 17.4c€/kWh including taxes produces the following results (Table 2).

Table 2. LCOE for a PV system of 6000Wp (5000W inverter) in Spain

PV Module Cost (€/Wp)	System Cost (€)	Production (kWh/year)	O&M (€)	Life time (years)	Discount rate	LCOE (€/kWh)
1.0	15,464	7,254	123.3	25	0.1102	0.2519
0.8	14,012	7,254	123.3	25	0.1102	0.2298
0.6	12,560	7,254	123.3	25	0.1102	0.2077
0.4	11,108	7,254	123.3	25	0.1102	0.1857
0.2	9,656	7,254	123.3	25	0.1102	0.1636

With the results obtained for the LCOE, we can conclude that Spain would reach grid parity under conditions where the PV modules cost between 0.2€/Wp and 0.4€/Wp.

A graphic representation can provide a clearer idea about the point at which the retail prices and generation cost reach equilibrium.

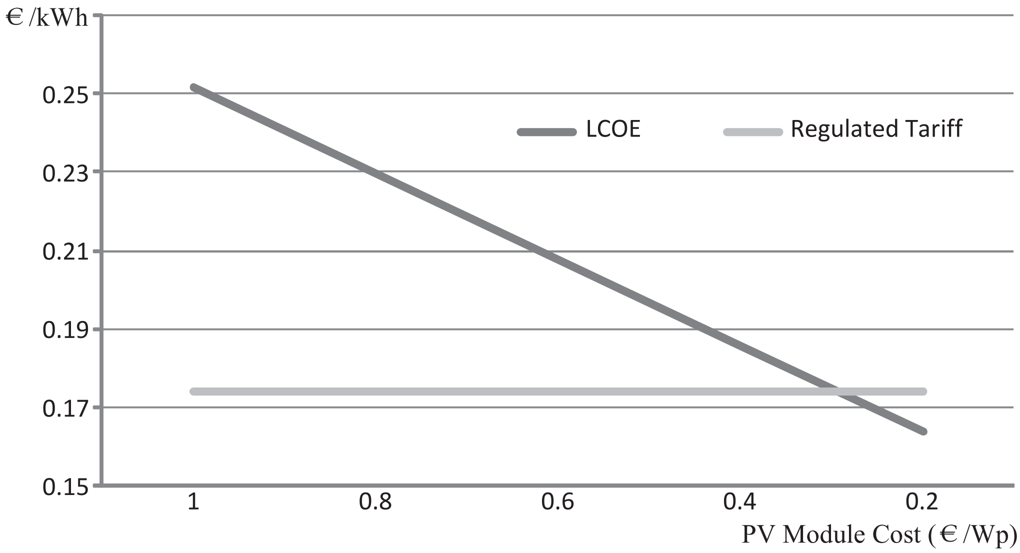

Fig.1 Graphic representation of the LCOE analysis with the regulated tariff at fixed interest conditions

We will analyze this case by introducing another variable, the interest rate, and then determine which bank terms and conditions can allow the system to achieve the regulated tariff target (Table 3).

Table 3. LCOE analysis for a PV system of 6,000Wp (5,000W inverter)

PV Module Cost	Interest Rate (%)				
(€/Wp)	12%	10%	8%	6%	4%
1.0	0.2888	0.2519	0.2167	0.1838	0.1535
0.8	0.2633	0.2298	0.1979	0.1681	0.1406
0.6	0.2378	0.2077	0.1792	0.1524	0.1278
0.4	0.2122	0.1857	0.1604	0.1368	0.1150
0.2	0.1867	0.1636	0.1417	0.1211	0.1022

Relating the results obtained on the last survey, we can determinate an interest rate between 6% and 8% could achieve the regulated tariff target for grid parity.

Conclusions

We have defined grid parity as the point at which the price of electricity is the same as the cost of generation (a mix of different generation sources: nuclear, natural gas, coal, petroleum, hydro, wind, PV, and others). This cost is levelized based on a reviewed formula that considers all the parameters described. The main conclusion is that grid parity depends on the PV system cost, the interest rate, and the retail cost of the electricity; these variables combined indicate when a system is close to achieving grid parity. Following this parameters we can predict that Spain is at a point very close to accomplishing grid parity

We are considering grid parity with a lifetime of 25 years for comparison with the feed-in tariff, but we must take into account the fact that the systems installed with a FiT model are amortized within a 10-year period. Therefore, this adds certain benefits when comparing grid parity with the feed-in tariff, creating a more attractive scenario.

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Article

Analysis of Photovoltaic Self-Consumption Systems

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Abstract: Components and installation prices could make the self-consumption of solar photovoltaic (PV) systems competitive. In this paper, we explore different self-consumption options, off-grid PV systems (with back-up generator and/or batteries), and grid-connected PV systems under net-metering policies. The calculation of the net present cost (NPC) reveals that the grid-connected PV-only case (for the net-metering scheme) is the most attractive from the technical and financial points of view, with a levelised cost of energy less than 0.1 €/kWh. Off-grid PV + Diesel + Batteries has a higher cost, around two or three times the grid-connected PV-only under net metering. Additionally, the off-grid PV + Diesel is less attractive from a financial point of view, which has a cost of around 10 times the PV-only under net metering. In addition, the values of life cycle CO_2 emissions in each of the cases studied have been compared, and we have concluded that although the off-grid PV + Diesel + Batteries system presents lower CO_2 emissions than the PV-only system, the existence of batteries does not allow one to affirm that the PV + Diesel + Batteries system is the best from an environmental point of view.

Keywords: photovoltaic tariffs; self-consumption; net metering; remuneration policies; grid parity

1. Introduction

Due to the many incentive programs that have been approved in the different countries where solar PV has been developed, PV generation has become one the most encouraged sources of energy generation [1]. In this context, there is a contrast between the various European PV markets. One of the main policy differences across the European countries is the possibility of consuming generated energy after it has been measured in the output meter (i.e., feed-in tariff (FiT)) [2]. When this option is enabled along with some kind of incentive scheme, the owner's cost per kilowatt-hour of energy consumed can be cheaper than that provided by the distributor network operator (DNO), as this system remunerates the owner for every kilowatt-hour generated. Most incentive schemes disappear over time [3] as their countries' markets grow. Therefore, the purpose of this paper is to start developing models to clarify the benefits associated with consuming all of the energy that a PV installation produces, even without financial support schemes such as FiT or a renewables obligation certificate (ROC). Assuming that grid parity is achieved, solar PV generation energy can be sold through the grid at a price similar to its purchase price. This scenario gives the energy provider multiple business opportunities, such as becoming a residential or commercial energy distributor. This scheme would create multiple miniature DNOs. For residential schemes, the risk is clearly defined and is comparable to that of a mortgage. Additionally, economic fluctuations and financial stability can vary by country [4]. Most of the developed countries in the world, including the United States, the United Kingdom, Italy, and Germany, are introducing self-consumption as their main solar PV development systems [5]. For example, the United States has promoted the market for distributed PV using net metering and support policies [6].

In the case of Spain, the decision to revoke the FiT [7] and the significant increase of electricity prices can turn self-consumption into an attractive concept due to its financial savings and stability [8,9].

In terms of self-consumption, several authors have analysed PV systems, both economically and environmentally.

The effect of the demand profile's temporal resolution in the design and economics of PV self-consumption systems was studied in [10,11], which determined that good results can be reached at temporal resolutions of between 5 and 60 min, although for the design of the storage system, it is advisable to use a relatively small temporal resolution (of at least 5 min). These studies show the need to continue investigating this topic.

Other authors have focused on the use of batteries, with some affirming that the use of batteries can favour the increase of self-consumption installations [12]. Despite the high cost of these batteries, using them can be profitable if the price of electricity increases enough [13]; if the consumer pays higher prices during peak demand hours, batteries can result in significant savings on the consumer's electricity bill [14]. The researcher in [15] studied the effect that the application of demand-side management (DSM) programs, in combination with energy storage, had on the design of PV self-consumption systems, determining that no linear relation exists between electricity flows and storage capacity. Regarding DSM programs, the result obtained in [16] showed that using batteries is more effective than implementing DSM programs to promote self-consumption. However, despite the possible economic benefits, the negative environmental effects associated with the use of batteries are not often considered [17]. These negative environmental aspects, if they are considered and evaluated, could discourage the use of batteries in grid-connected systems.

Other studies about PV self-consumption systems have been conducted in various countries [18–22]. The results achieved show that, in many cases, self-consumption is economically viable, although its profitability depends on the regulatory policies that exist in each country. As the types of applicable rates determine the profitability of these installations [23], a proper normative regulation is needed to promote self-consumption [24].

Considering all of the above, this paper presents a study about self-consumption in Spain (both off-grid PV systems with batteries or diesel generators and grid-connected PV systems under net-metering policies), focusing on the economic and environmental aspects. The NPC is calculated in this economic study [25] for all cash flows during the system's lifetime (e.g., acquisition and installation costs, operation and maintenance costs, and replacement costs for components when their lifespan ends); the authors then converted to the initial system time by means of standard economic statistics (e.g., interest rate and inflation rate). In addition, the levelised cost of energy (LCOE) is obtained by dividing the NPC by the total load consumed during the system's lifetime. In this research's environmental study, the CO_2 emissions for all components' life cycles are evaluated.

This paper focuses particularly on Spain's irradiance zone three (III), which includes the majority of Spain's mid-peninsular land. This zone includes Zaragoza, Madrid, most of Catalonia, Castilla Leon, Castilla La Mancha, Comunidad Valenciana, Extremadura, and Andalucía. The average household energy consumption is considered.

As a tool for the simulations and optimisations, the software iHOGA (improved Hybrid Optimisation by Genetic Algorithms, Dufo-López R., Zaragoza, Spain) [26] has been used. iHOGA is a simulation and optimisation software tool that optimises the hybrid renewable system, simulating the performance of the system on an hourly time-step basis throughout a whole year (which is supposed to be repeated until the end of the system's lifetime) or during the battery lifetime in the cases in which there is a battery in the system (when the battery's life ends, the old batteries are replaced with new ones, and the performance during the battery's lifetime is supposed to be repeated until the end of the system's lifetime). Systems with different combinations of components are tested to simulate their operation and to determine their performance during the system's lifetime. When systems comply with technical requirements, the NPC is calculated; across all the evaluated cases, the system lifetime averaged about 25 years (as is usual for PVs); the average interest rate was 4%; and the general inflation rate was 2%. Cash flows were analysed on a yearly basis. The main data input into iHOGA were system components, electricity demand, renewable resources, technical parameters, and economic parameters. More references about iHOGA can be found in previous papers [27,28].

In this study, we assume that retail prices and net metering policies will not vary. The inclusion of changes to the retail rate design for distributed PV systems [29] and/or to the tariff policy [30] can affect the on-grid, PV-only system's results. The authors expect to address these research topics in future works.

This work is presented as follows: Self-consumption methods; Economic and energy data; Study cases; and Conclusions.

2. Self-Consumption Methods

The three self-consumption methods studied in this work are off-grid PV + Diesel systems, off-grid PV + Diesel + Batteries systems, and grid-connected PV-only systems under the net-metering policy [31]. The NPC and LCOE are used to determine the profitability of the different systems studied. The NPC or LCOE methodology allows one to calculate the required system and financial expenses necessary for each particular case [32]. However, one must consider that the LCOE is not the same as electricity prices; it is used as a proxy for the total price paid by consumers while considering as many realistic costs as possible.

Next, the three methods of self-consumption are briefly described.

2.1. Off-Grid PV + Diesel System

Figure 1 shows the basic elements for this system. In this case, the off-grid PV system uses a diesel generator as backup power supply when the PV panels do not provide the energy that the load demands. The lifespan of the generator has been considered, which mainly depends on the amount of hours it runs and its consumption of diesel.

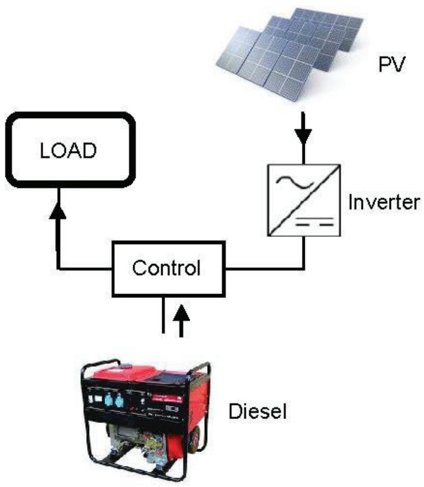

Figure 1. Off-grid PV + Diesel system.

2.2. Off-Grid PV + Diesel + Batteries System

Figure 2 shows the basic elements for this system. Storing the energy within batteries is advisable in off-grid PV systems, as there are periods without solar irradiation. Batteries store or supply energy depending the demand and generation. On the other hand, storing the energy within batteries increases the capital expenditure (CAPEX) and the operation and maintenance expenditure (OMEX), as the batteries need to be controlled and refilled. Additionally, after several years, their lifespans end, and they must be replaced. However, as diesel fuel consumption can be reduced, OMEX is reduced more prominently.

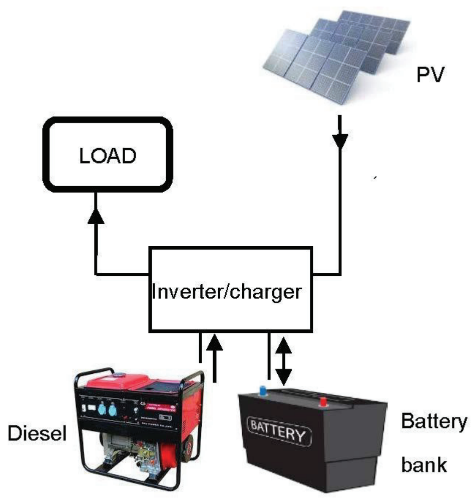

Figure 2. Off-grid PV + Diesel + Batteries system.

The models of the components are shown in [25]. The batteries' lifespan has to be considered within the finance scheme. The batteries considered in this paper are OPzS lead-acid with a cell voltage of 2 V. The aging of the batteries is calculated using an advanced model created by Schiffer et al. in 2007 [33,34] that considers the capacity loss due to degradation of the active mass (taking into account the state of charge versus time, the current, the gassing, and the acid stratification) and capacity loss due to corrosion (considering the effect of temperature and voltage).

The lead–acid batteries stand out for their reliability and low cost [35]. In the future, it is possible that they will be replaced by lithium–ion batteries, which possess greater efficiency and longer lifetimes, but their higher cost implies that lead–acid batteries should continue to be the most used in renewable energy installations [36].

2.3. Grid-Connected PV-Only System under Net-Metering Policy

Figure 3 shows the basic elements for this system. Net metering allows the possibility that the consumer-generator uses the electricity produced directly. In addition, the excess energy can be injected into the grid and can use the grid like a storage system [8,37]. Effectively and financially, it is the best system, as no local physical storage system is needed, so a considerable reduction of CAPEX OMEX is expected.

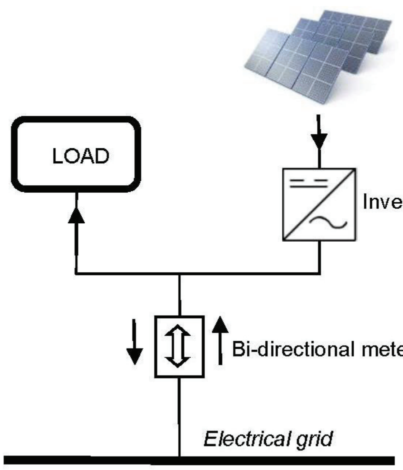

Figure 3. Grid-connected PV-only system under net-metering policy.

3. Energy and Economic Data

Depending how accurately the system is calculated, the profitability of a system can be determined with high or low precision. A simple house with all the requirements for living in a modern society has been considered.

The total installed solar PV system cost includes the modules, inverter, support structure, electrical low-voltage circuits and protections, cables and structure anchor, engineering, mechanical installation, electrical installation, and value-added tax (VAT). The components can be weighted in order of price, which are the solar modules, inverter, structure, batteries, and manpower. Over the last five years, system costs have decreased by as much as 25% of their initial cost. This implies that it is possible to make the system competitive against other technologies and against the retail electricity price [32].

Next, we describe the data used in this study.

3.1. Meteorological Data Sources

There are many solar irradiance meteorological data sources available. Some of them are based on private weather stations. In this work, data from the Photovoltaic Geographical Information System (PVGIS) [38] have been used. The values for a place at zone III in Spain, with a slope of 15° and oriented to the south, are shown in Table 1.

Table 1. Irradiance at zone III in Spain (Zaragoza).

Month	E_d	E_m	H_d	H_m
January	2.09	64.70	2.61	80.90
February	3.13	87.70	3.94	110.00
March	4.21	131.00	5.46	169.00
April	4.50	135.00	5.96	179.00
May	4.96	154.00	6.74	209.00
June	5.31	159.00	7.38	221.00
July	5.57	173.00	7.80	242.00
August	5.06	157.00	7.04	218.00
September	4.33	130.00	5.86	176.00
October	3.33	103.00	4.38	136.00
November	2.39	71.70	3.03	91.00
December	1.91	59.10	2.38	73.80

E_d: Average daily electricity production per kWp of the PV system (kWh/kWp); E_m: Average monthly electricity production per kWp of the PV system (kWh/kWp); H_d: Average daily sum of global irradiation per square meter received by the modules of the given system (kWh/m^2); H_m: Average sum of global irradiation per square meter received by the modules of the given system (kWh/m^2).

The reason why we are using a 15° tilt angle is because it is a common inclination for a roof in that area of Spain. Nevertheless, the optimal angle for an installation connected to the grid would be 35° tilt angle (maximising the electricity production of the whole year) and 60° for an off-grid system (maximising the electricity production of the month with the lowest irradiation, usually December).

3.2. PV Panels

The PV panels comprise nearly 50% of the budget (in grid-connected PV systems). The influence of Chinese manufacturers has reduced the global price of the system, but recently, anti-dumping policies have stopped this tendency [39]. Regulations imposed by the European Union say that it cannot be possible to assume lower prices for Chinese-manufactured solar panels [40].

The size of the installation directly affects the cost of the panels. In this case, we consider installations below 10 kW. After reviewing the market, in 2016, the solar module price is around 0.55 €/Wp for a 5 kW system.

3.3. Mounting Structures

There are different prices depending on whether the structure is aluminium or hot galvanised steel. In the past, aluminium was a very expensive metal, making the hot galvanised mounting structures more competitive. Aluminium structures were priced at 0.34 €/Wp, but this price has decreased by 50% over the past few years because aluminium is more than 50% cheaper in 2016 than it was in 2007 [41]. Typically, the mounting system on a rooftop installation is aluminium because it is lighter than the galvanised steel. With this in mind, we consider an aluminium structure in our budget.

3.4. Inverters

A solar inverter converts the DC output power from the solar panels into AC electricity that is synchronised with the AC frequency of the grid. For domestic applications, string inverters are the most used, and single-phase systems are the most common configuration on houses. For industrial or large-scale applications, a central inverter could be used. In this work, we consider a string inverter because of the size of the studied installations. Prices are around 0.1 €/Wn for an industrial inverter and 0.24 €/Wn for a 5 kWn inverter, considering a European manufacturer. These prices are obtained through market research. The efficiency of the system could be improved using microinverters, but at the moment they are not very common in the market due to their high price.

3.5. Energy Balance

Sizing the system depends on the load consumption. Off-grid systems must be dimensioned following the worst-case scenario of consumption and also the worst-case scenario of generation (usually winter time). Furthermore, there are periods in which the energy produced by the system is greater than consumption and vice versa. However, grid-connected systems under net-metering policies should be dimensioned to produce approximately the same energy as the total energy consumed during the year.

Considering a solar PV generator installed in the roof of a house, the power consumption of a typical household located in Spain has been modelled.

The total consumption or energy demand per day is calculated using Equation (1).

$$Total\ consumption\ (\frac{Wh}{day}) = \sum (Units \cdot Power \cdot Hours\ per\ day\ used) \tag{1}$$

where *Total consumption* is the total electricity demand in the worst-case consumption scenario; *Units* is the number of units of the same item present in the house; *Power* is the maximum instant power consumed by the item; and *Hours per day used* is the number of hours per day of estimated use.

The house considered in this work has a power consumption of 10,000 Wh per day (a typical household load in Spain). The hourly consumption for the day (which is supposed to be repeated every day) is shown in Figure 4. The assumption that the behaviours of the tenants are constant all year has been considered; therefore, the hourly consumptions are the same, as some components and loads, like heaters, have been disregarded under the assumption that they are powered by gas. There is a demand peak at 21:00, usual in households in Spain. In Spain, it is common for dinner to start at 20:00, 21:00 or 22:00.

Demand growths have not been considered as it is a household load. The electrification of the house could be increased in the future (adding, for example, more automation for opening/closing window blinds, etc.); however, it has been considered that home appliances will consume less energy in the future, being more efficient, which can compensate for the increase in electrification.

The production generated over one year changes depending the amount of sunlight and the weather. Since the power production balance is not regular, the energy balance has to be regularised either with a storage system (batteries), backup diesel generator, or the AC grid (FiT or net-metering scheme). In this work, FiT has not been considered, as it tends to disappear.

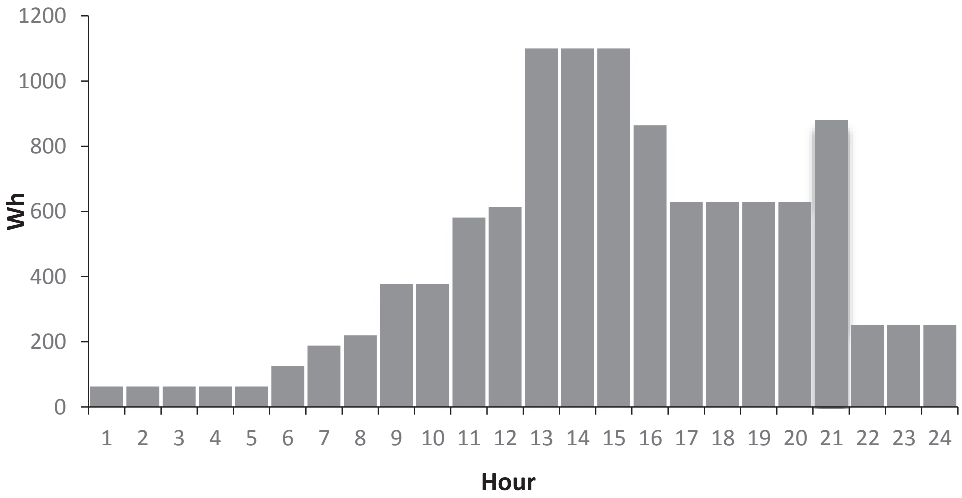

Figure 4. AC loads in a house throughout the year on an hourly basis.

4. Study Cases

4.1. Off-Grid PV + Diesel System

The following subsections describe the economic and environmental aspects of this system, and the final results are shown and analysed.

4.1.1. Cost and CO_2 Emissions of the PV + Diesel System

To analyse the economic attractiveness of the PV + Diesel system, the costs of the solar PV panels, inverter controller (with maximum power point tracking (MPPT) to obtain the maximum power from the PV), the controller, and the diesel generator must be known. iHOGA software includes a section to introduce the financial parameters in case a loan is considered. In this work, loans to finance the PV system were not considered.

All of the prices introduced into iHOGA have been extracted from market research and are average reference prices (Table 2). In addition, life cycle CO_2 emissions of the different components, including manufacturing, transport, mounting, disassembling, and recycling [42], are shown in Table 2.

Table 2. Prices of the used components.

Component	Price per Watt (€/W) (Market Research)	Life Cycle CO_2 Emissions [42]
PV Panel	0.55	800 kg/kWp
Mounting structure	0.34	Included in PV panel
Diesel Generator	0.42	3.5 kg/litre of diesel fuel
Inverter with MPPT	0.24	Neglected
Controller	0.31	Neglected

The cost of the diesel fuel considered in this work is 1.3 €/L, with an expected annual fuel inflation rate of 5%. The lifespan considered for the diesel generators is 10,000 running hours.

The cost of the rest of the system (electrical low voltage circuits and protections, electrical installation, mechanical installation, and engineering) has been considered as a fixed cost of €300 + 2% of the total cost of the components. DC bus voltage is 48 V and AC bus is 230 V. PV panels of 280 Wp and 24 V of nominal voltage have been considered, and two panels must be connected serially in order to obtain 48 V in the DC bus. The number of strings of PV panels in parallel can vary from 0 to 12. Inverters considered range from 0 to 1.8 kW in 0.6 kW steps. The diesel generators considered are of 0, 1.9, and 3 kVA. The software will consider the different combinations of components, simulating all of them and obtaining the economic results for each combination.

4.1.2. Analysis and Simulation

In this work, the objective is to minimise LCOE [32] or the NPC. The software allows other objectives for optimisation, but in this case, the main objective is to minimise LCOE (i.e., minimise NPC). For this purpose, the results given by iHOGA have been sorted from top (the best or lowest NPC) to bottom (the worst or highest NPC). The results are shown in Table 3.

Table 3. Main results of the best combinations given by iHOGA solar PV + Diesel.

Project	NPC (€)	PV Power (Wp)	Diesel-Generator Power (VA)	Inverter Power (W)	Life Cycle CO_2 Emissions (kg/year)	LCOE * (€/kWh)
1	84,546.67	5040	1900	1800	5502.58	0.927
2	84,966.16	4480	1900	1800	5547.78	0.931
3	86,084.03	3920	1900	1800	5632.78	0.943
4	87,056.42	3360	1900	1800	5717.98	0.954
5	89,193.91	2800	1900	1800	5882.74	0.977
6	94,039.39	2240	1900	1800	6239.74	1.031
7	106,169.12	1680	1900	1800	7108.84	1.163
8	120,735.10	5040	3000	1800	8494.37	1.323
9	121,567.34	4480	3000	1800	8574.74	1.332
10	123,412.16	3920	3000	1800	8717.81	1.352

* LCOE (€/kWh) = NPC/(10 kWh/day·365 days/year·25 years).

As mentioned previously, the purpose of this simulation is to find out which is the best configuration in financial terms; therefore, Project 1 (Table 3), which has the best NPC (€84,546.67), will be analysed in detail. Project 1 is composed of 18 PV panels of 280 Wp (connected in strings of two panels in serial, and nine strings in parallel), with a peak power of 5.04 kWp. The diesel generator has 1.9 kVA of power, and the inverter has 1.8 kW of power. The inverter size is adequate to supply the maximum load. The PV generator's maximum power is much higher than the rated power of the inverter (2.8 times). This means that a part of the energy produced by the PV generator will not be used. In spite of this, it is the optimal system. This is due to the fact that a smaller number of panels would imply an increased annual consumption of diesel, giving rise to a high NPC. In addition, Table 3 shows the relationship between the NPC and the lifecycle CO_2 emissions, which are calculated with consideration of the lifecycle emissions (manufacturing, transport, mounting, disassembling, and recycling the components), as shown in [42].

The results show that the most rentable system (Project 1) is also the most beneficial for the environment, as it is the option with the fewest CO_2 emissions.

4.1.3. Financial Evaluation

The financial results and cash flow provided by iHOGA for the best combination of components (Project 1) is shown graphically in Figure 2, which provides information about how to structure the cash flow during the life cycle of the installation. The cash flow in the last year is dramatically smaller than the previous years because it is assumed that at the end of the system's lifetime the remaining value of the components of the system is obtained by selling them. For example, if at the end of the system's lifetime (year 25) the diesel generator has performed at 50% of its lifetime, then it is expected to obtain cash flow by selling it at 50% of its acquisition cost.

Figure 5 shows that there are some years in which the cash resources need to be higher than others. Years 11 and 21 are the most expensive, as some components, like the inverter, need to be replaced at this time. On the other hand, the diesel generator has to be replaced every two years. Thus, every two years, the price of the generator is added into the expected cash flow.

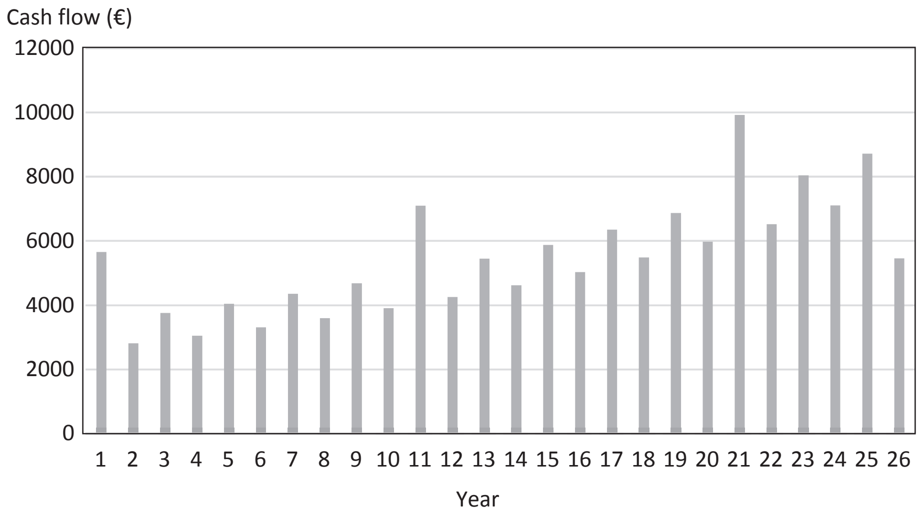

Figure 5. Cash flow of the solar PV system with a diesel generator.

4.1.4. Sensitivity Analysis

A sensitivity analysis has been performed considering the variation in PV panel costs (comparing the base case of 0.55 €/Wp and a case to a higher PV cost of 1 €/Wp) and the variation of the annual inflation of diesel fuel (comparing the base case of 5% to 3%, 1%, and −1%).

Figure 6 shows the main results (PV size, NPC, and life cycle CO_2 emissions) of the optimal solution found for the case of PV costs of 0.55 €/Wp, with a varying annual fuel inflation rate. All of the optimal solutions have the same configuration: PV of 5.04 kWp, diesel generator of 1.9 kVA, and inverter of 1.8 kW. Since all of them have the same fuel consumption, emissions are the same. However, the NPC falls as the annual fuel inflation price decreases.

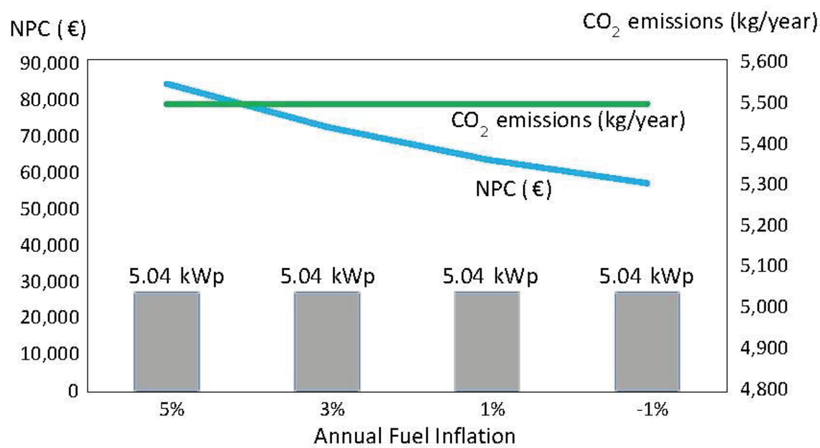

Figure 6. PV + Diesel systems. Optimal solutions include cases with a PV cost of 0.55 €/Wp.

Figure 7 shows the main results of the optimal solution found for the case of a PV cost of 1 €/Wp, with varying annual fuel inflation rates. The optimal solutions for 5% and 3% have same configuration as the ones in Figure 6. However, the optimal solutions for 1% and −1% include a lower PV generator (and therefore higher fuel consumption and emissions); the optimal solution is as follows: PV of 4.48 kWp, diesel generator of 1.9 kVA, and inverter of 1.8 kW. Comparing Figure 6 with Figure 7, the NPC of the cases of PV 1 €/Wp are a little higher than the cases of PV 0.55 €/Wp. There is a small difference in NPCs between Figures 7 and 8 because the main change in the NPC is due to fuel consumption, while the PV generator cost is a minor factor of the NPC. Thus, the variable which most affects the NPC of PV + Diesel is the annual fuel price inflation.

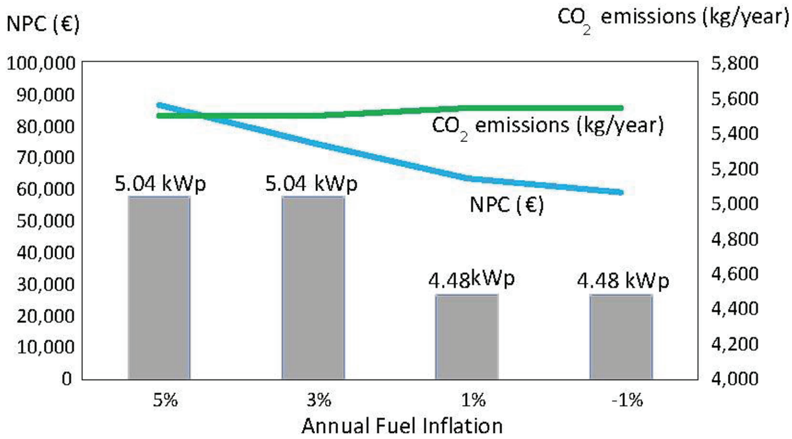

Figure 7. PV + Diesel systems. Optimal solutions include cases with a PV cost of 1 €/Wp.

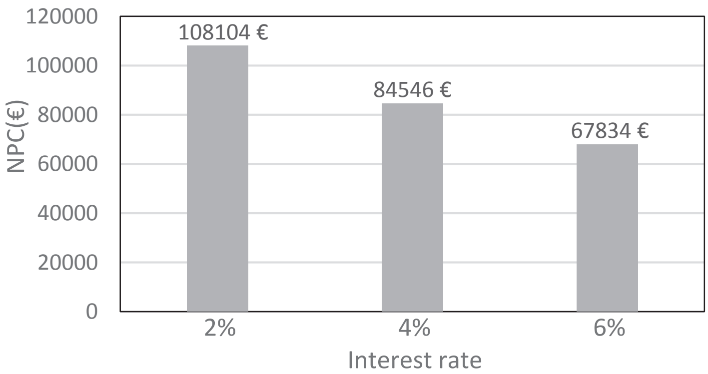

Figure 8. PV + Diesel systems. Effect on the NPC of the interest rate.

Another sensitivity analysis has been performed that takes the variation in the interest rate into consideration. The base case uses a 4% interest rate, and two other cases—2% and 6%—have been analysed. In all cases, the optimal system is the same, but the NPC is highly affected, as shown in Figure 8.

Finally the effect of the loan has been evaluated. The base case uses no loan. Another case has been optimised that considers a loan of 80% of the initial acquisition cost of the system paid over 10 years with an interest rate of 7%. The optimal system is the same. However, the NPC is now of €85,247. There is no high increment in NPC due to the loan, as the NPC is poorly affected by the initial acquisition cost of the system.

4.2. Off-Grid PV + Diesel + Batteries System

In this case, the batteries can supply the load when there is not enough generation from the PV panels. The cases of Diesel + Batteries (without PV) and PV + Batteries (without diesel) are also considered. In the cases of PV + Batteries (without diesel), dimensioning the batteries depends on the required number of days of autonomy. In these cases, a minimum of four days of autonomy has been considered. The batteries considered are OPzS lead–acid, with a range of 180 Ah to 2800 Ah of nominal capacity, nominal cell voltage of 2 V, 1254 full cycles to failure, and a 20% minimum-allowed state of charge (SOC). As the DC bus is 48 V, 24 batteries must be connected serially. The sizes of the

PV, diesel and inverter/charger taken into account are same as in the previous section. The number of battery strings in parallel considered are from 0 to 4. In this case, the inverter/chargers is considered, which is an inverter with a battery charger and control unit, including the battery controller (to prevent overcharge and over-discharge) and battery charger (so that the diesel can charge the battery bank). The control strategy is "load following" so that when there is inadequate power from the PV, the battery will supply the load; the diesel generator will only run to supply the load when the batteries reach a low SOC (20%). The battery bank is charged by the PV, but the inverter/charger forces the diesel to periodically (every fourteen days or after eight nominal charge throughputs) fully charge the battery bank.

4.2.1. Cost and Emissions of the System (PV + Diesel + Batteries)

The costs of previous sections (Table 2) are considered. The considered battery cost is 352 €/kWh of nominal capacity, and the inverter/charger has a cost of 1.35 €/W (these are based on market research and are average reference prices). In order to calculate the cost to replace the batteries, we assume a reduction in their acquisition cost by 2% annually, with a maximum reduction of 60%. Again, no loans have been considered to finance the PV system. Life cycle CO_2 emissions of the batteries are 55 kg/kWh [42], while the emissions of the electronic components are negligible.

4.2.2. Analysis and Simulation

The objective is to minimise the LCOE (or the NPC). The results are sorted from top (the best or lowest NPC) to bottom (the worst or highest NPC) (Table 4). The best configuration, in financial terms, is Project 1, which is the one with the best NPC (€20,039.73).

Table 4. Main results of the best combinations given by iHOGA solar PV + Diesel + Batteries.

Project	NPC (€)	PV Power (Wp)	Diesel-Generator Power (VA)	Battery Bank (Wh)	Energy Supplied by Diesel (%)	Life Cycle CO_2 Emissions (kg/year)	LCOE (€/kWh)
1	22,039.73	3920	1900	8640	1.48	297.38	0.242
2	22,274.81	4480	1900	8640	1.07	288.27	0.244
3	22,729.77	5040	1900	8640	1.04	305.09	0.249
4	22,915.09	3920	3000	8640	2.27	353.31	0.251
5	22,959.44	4480	3000	8640	1.59	326.97	0.252
6	23,402.75	5040	3000	8640	1.56	342.72	0.256
7	23,448.29	3920	1900	18,720	0.03	289.23	0.257
8	23,714.68	3920	3000	18,720	0.05	290.28	0.260
9	24,205.69	4480	1900	18,720	0.01	314.26	0.265
10	24,230.97	3920	1900	12,960	0.22	249.2	0.266

Project 1 is comprised of 14 panels connected serially in seven strings of two, with a peak power of 3.92 kWp. The diesel generator has 1.9 kVA of power, and the inverter/charger is 1.8 kW. In this case, there is a unique string of 24 batteries of 180 Ah in series, providing a total capacity of 8.64 kWh. The PV generator/inverter power ratio is 2.18. Again, this difference is because with a lower PV generator, the annual consumption of diesel would be more expensive due to the amount of hours needed to supply the power demanded.

Comparing for example Projects 1 and 3, it can be seen that CO_2 emissions are higher for Project 3 than for Project 1, however, PV power is higher in Project 3 and therefore the energy supplied by diesel (and therefore the fuel consumption) is lower. This is because the CO_2 emissions (kg/year) have been calculated to include all the emissions in the lifetime of the system, divided by 25 years. It considers not only the emissions due to the diesel fuel, but also the emissions due to the manufacturing, transport, mounting, disassembling, and recycling of the components of the system (PV, diesel generator and battery bank). A higher PV generator means more CO_2 emissions due to the manufacturing, transport, mounting, disassembling, and recycling of the PV generator.

4.2.3. Sensitivity Analysis

A sensitivity analysis has been performed considering the variation in PV panel cost (comparing the base case of 0.55 €/Wp to a case with a higher PV cost of 1 €/Wp), the variation of battery cost (comparing the base case of 352 €/kWh to other cases of 250 €/kWh and 450 €/kWh), and the variation of the annual inflation of diesel fuel (comparing the base case of 5% to 3%, 1%, and −1%).

Figure 9 shows the NPC of the optimal solutions found for each combination of PV price, battery price, and annual fuel inflation. All of the optimal solutions are the same configuration and therefore same emissions: PV of 3.92 kWp, diesel of 1.9 kVA, inverter/charger of 1.8 kW, and battery bank of 8.64 kWh. NPC varies from around €19,000 to €26,000. In this case, the annual fuel inflation did not have a great influence on NPC. However, the price of PV panels and batteries did have an important influence.

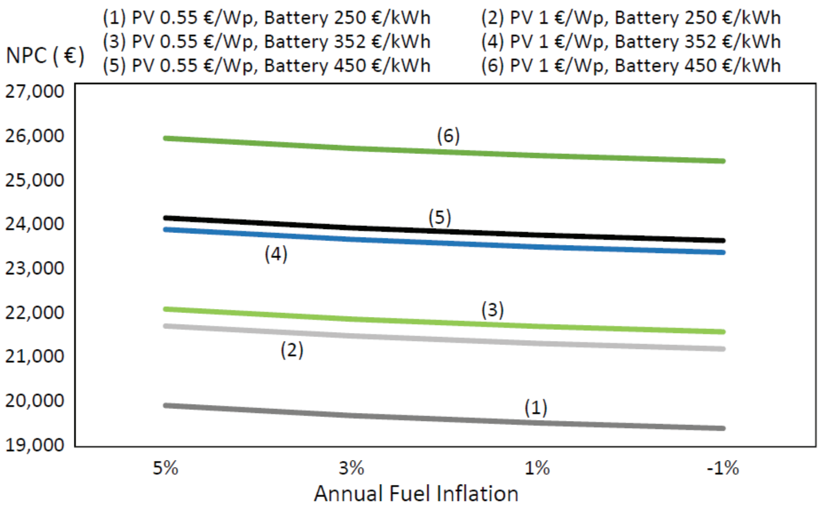

Figure 9. Sensitivity analysis, PV + Diesel + Battery systems. NPC of the optimal solutions.

Another sensitivity analysis has been performed with consideration for the variation of the interest rate. The base case uses a 4% interest rate, and two other cases have been analysed: 2% and 6%. In all cases, the optimal system is the same. However, the NPC is affected, but less than in the case of PV + Diesel, as shown in Figure 10.

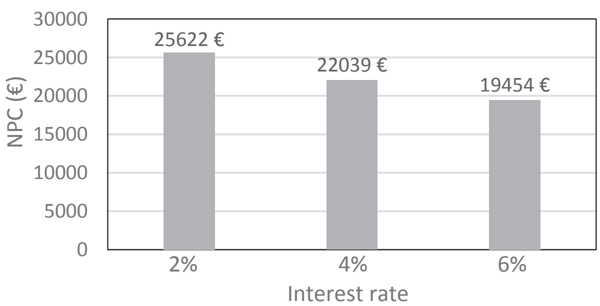

Figure 10. PV + Diesel + Battery systems. Effect on the NPC of the interest rate.

Finally the effect of the loan has been evaluated. The base case uses no loan. Another case has been optimised that considers a loan of 80% of the initial acquisition cost of the system paid over 10 years with an interest rate of 7%. The optimal system is the same, but the NPC is now of €27,386. There is a notable increment in NPC due to the loan, as NPC is affected by the initial acquisition cost of the system.

4.3. Grid-Connected PV-Only System under Net-Metering Policy

In this case, the house is grid connected under a net-metering scheme. In this work, the modality of net metering considered is "net metering, one-year rolling credit" [8], as it is the most widely used scheme. In this net-metering scheme, all of the energy injected in the electrical grid can be consumed for free throughout year, but if the energy injected is higher than the energy consumed from the grid, there is no buyback possibility. Injecting energy into the grid does not imply adding any technical components or cost (for example, in the United States a net metering scheme is used in most of the states, without extra costs), though there could be an administrative cost depending on the country or region in which this scheme is developed. The PV panels and inverters in Section 4.1, Table 2, have been considered. The purchasing price of the energy is 15 euro cents per kWh for the base case, with an expected inflation of 3% annually. Again, no loans were considered to finance the PV system, and all of the prices introduced into iHOGA are the same as in the previous sections. Life cycle CO_2 emissions of the energy consumed from the AC grid depend on the electricity mix of the grid in the given country. A value of 0.4 kg/kWh was considered [42], which will be applied to the amount of energy consumed from the AC grid that was not previously injected in the grid (i.e., applied to the difference between the energy consumed from the AC grid and the energy injected into the AC grid).

4.3.1. Analysis and Simulation

The results of the optimisation (minimisation of NPC or LCOE) have been classified from top (the best NPC) to bottom (the worst NPC; Table 5). The last one (Project 10) is a case without a PV system, (i.e., all of the energy demanded by the load is bought from the AC grid).

Table 5. Project results given by iHOGA. Solar PV on net-metering scheme.

Project	NPC (€)	PV Power (Wp)	Inverter Power (W)	Life Cycle CO_2 Emissions (kg/year)	LCOE (€/kWh)
1	6992.04	2240	1800	536.35	0.077
2	7283.79	2800	1800	528.34	0.080
3	7992.29	3360	1800	532.1	0.088
4	8700.79	3920	1800	540.31	0.095
5	9054.32	1680	1800	585.91	0.099
6	9409.29	4480	1800	551.05	0.103
7	10,117.78	5040	1800	563.49	0.111
8	11,235.35	1120	1800	778.75	0.123
9	13,534.41	560	1800	1113.97	0.148
10	15,057.88	0	0	1459.99	0.165

The best configuration, in financial terms, is Project 1, which had the best NPC (€6992.04), composed of eight panels (two connected serially and four strings in parallel), with a peak power of 2.24 kWp. The inverter has 1.8 kW of nominal power. The solar PV system cannot cover the whole load demanded by the house, so the rest of the energy demanded has to be supplied by the grid. Project 1 is one of the most beneficial options for the environment.

Comparing Projects 2 and 4, we can see that increasing the PV power does not always imply decrement of the CO_2 emissions. As the PV generator power increases, the energy supplied from the AC grid decreases, decreasing the CO_2 emissions associated to that energy (a value of 0.4 kg/kWh has been considered). The emissions from PV (the manufacturing, transport, mounting, disassembling, and recycling of the PV generator) are lower than 0.4 kg/kWh. However, as PV generation increases, under net metering it can happen that the energy generated by the PV during the year is higher than the energy consumed by the load, then the excess energy injected into the grid will not be returned. This is why Project 4 has more emissions than 2. Project 4 uses a 3920 Wp PV generator, generating around 7000 kWh/year. If the load consumes 3650 kWh/year, then there are 7000 − 3650 = 3350 kWh/year injected into the grid that are not used later by the load.

4.3.2. Sensitivity Analysis

A sensitivity analysis has been performed considering the variation in PV panel cost (comparing the base case of 0.55 €/Wp to a case with a higher PV cost of 1 €/Wp), the variation of the purchased electricity price (comparing the base case of 0.15 €/kWh to 0.1 and 0.2 €/kWh), and the variation of the inflation of the purchased electricity price (comparing the base case of 3% to 1% and 5%).

Figure 11 shows the NPC of the optimal solutions found for each combination for PV price, electricity price, and annual electricity price inflation. All of the optimal solutions have the same configuration and therefore the same life cycle emissions (PV of 2.24 kWp, inverter of 1.8 kW, with 536 $kgCO_2$/year), except for the cases of 0.55 €/Wp, 0.2 €/kWh, 3% and 5% and the case of 1 €/Wp, 0.2 €/kWh, 5%, for which optimal solutions are a PV of 2.8 kWp and an inverter of 1.8 kW (with life cycle emissions of 528 $kgCO_2$/year). Electricity price inflation did not have a great influence on NPC. However, the price of PV panels did have a great influence, and the price of electricity had a relatively low influence (as in the optimal systems, the amount of the energy injected into the AC grid is a little lower than the energy consumed from the AC grid).

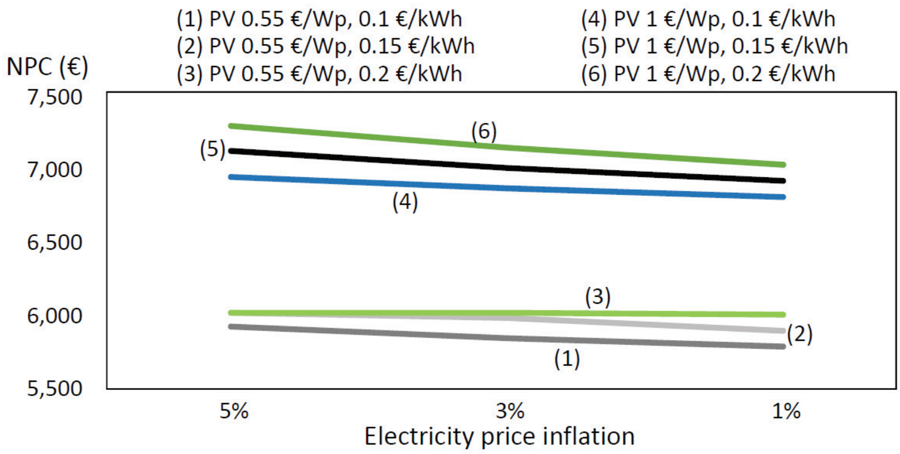

Figure 11. Sensitivity analysis, PV-only systems under net-metering scheme. NPC of the optimal solutions.

Another sensitivity analysis has been performed with consideration for the variation of the interest rate. The base case uses a 4% interest rate, and the other two cases have used rates of 2% and 6%. In all cases, the optimal system is the same. However, the NPC is barely affected, as shown in Figure 12.

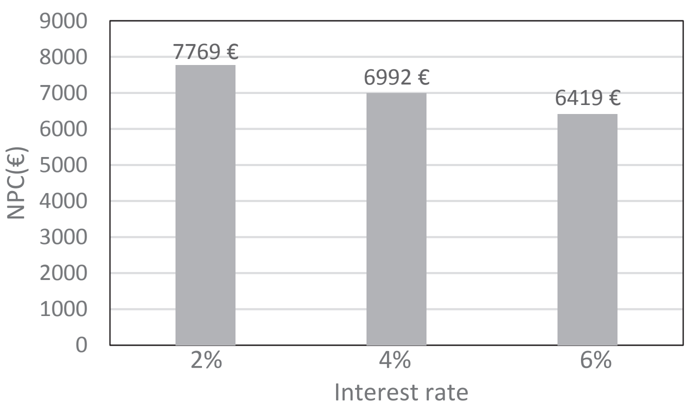

Figure 12. PV-only systems. Effect on the NPC of the interest rate.

Finally the effect of the loan has been evaluated. The base case uses no loan, while another case has been optimised considering a loan of 80% of the initial acquisition cost of the system with an interest rate of 7% over 10 years. The optimal system is the same. However, the NPC is now of €7381. There is a low increment in NPC due to the loan, as the NPC is poorly affected by the initial acquisition cost of the system.

5. Comparison of the Optimal Results of the Base Cases

Focussing on only the financial point of view, the NPC of the optimal combinations of each case are shown in Figure 13.

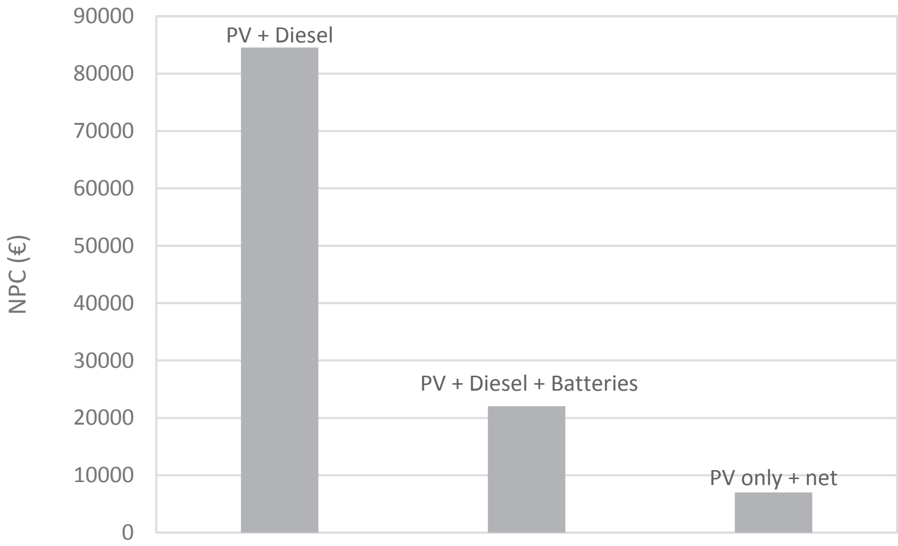

Figure 13. NPC of the different schemes. All cases represented.

PV + Diesel is the least attractive case financially compared to the other cases, while on-grid PV-only under net metering is the best configuration.

Considering environmental aspects (life cycle CO_2 emissions), Figure 14 shows that PV + Diesel + Batteries emits the least amount of CO_2.

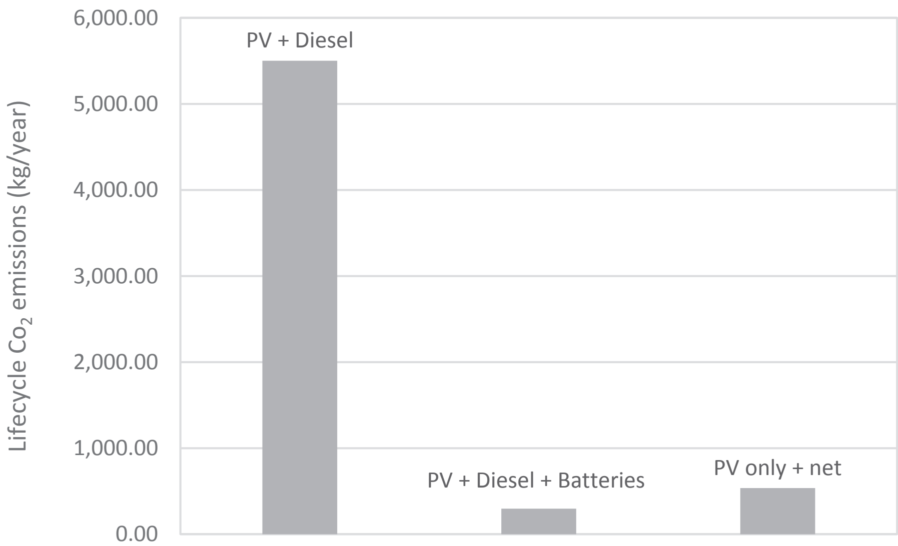

Figure 14. Lifecycle CO_2 emissions of the different schemes. All the cases represented.

In this study, we have taken into account the CO_2 emissions caused by the production, transportation and recycling of the batteries, but all the negative environmental impacts of the use of batteries has not been evaluated and considered. This topic has been widely studied by other authors [17,43,44], and it is possible to affirm, on the basis of these works, that the existence of batteries in the PV + Diesel + Batteries system still makes the PV-only system the best for the environment.

Table 6 shows a summary of the optimal solutions obtained in each case study.

Table 6. Summary of the optimal project results obtained by iHOGA.

Case Study	Off-Grid/ Net-Metering	Optimal Configuration				NPC (€)	LCOE (€/kWh)	Life Cycle CO_2 Emissions (kg/year)
		PV Size (kW)	Inverter (kW)	Diesel Generator (kVA)	Battery Size (kWh)			
PV + Diesel	Off-grid	5.04	1.8	1.9	N/A	84,546	0.927	5502
PV + Diesel + Batteries	Off-grid	3.92	1.8	1.9	8.64	22,039	0.242	297
PV-only + Net	Net-metering	2.24	1.8	N/A	N/A	6,992	0.077	536

6. Conclusions

This paper presented the optimisation of three different kinds of photovoltaic-based systems to supply the electrical load of a typical household (10 kWh/day). The systems considered were: (1) off-grid PV + Diesel; (2) off-grid PV + Diesel + Batteries; and (3) on-grid PV systems under net metering with one-year rolling credit modality. The results show that the PV system under the net-metering scheme is the one with lowest NPC and LCOE, around two or three times lower than off-grid PV + Diesel + Batteries and around 10 times lower than off-grid PV + Diesel. Moreover, although lower CO_2 emissions occur in the PV + Diesel + Batteries system, the on-grid PV-only system under net metering is better in environmental terms because it does not use batteries. The sensitivity analyses showed that the variables which most affects the NPC of the optimal PV + Diesel are the annual fuel price inflation and the interest rate. In the case of PV + Diesel + Batteries, fuel inflation did not have a great influence on NPC, though the price of PV panels and batteries did have an important influence. In the optimisation of the on-grid PV-only system under net metering with one-year rolling credit modality, the variable which most affected the NPC of the optimal system was the price of PV panels.

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Evaluating the Effect of Financing Costs on PV Grid Parity by Applying a Probabilistic Methodology

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Abstract: This paper presents a study that analyses the effect of financing costs on grid parity in photovoltaic (PV) installations by applying a probabilistic methodology. Three different case studies, located in Spain, have been considered, with 500 kW, 50 kW and 5 kW grid-connected PV generators. The technical and economic calculations were performed, considering the interest rate, yield across the Spanish geography, and PV module cost as parameters. The Monte Carlo method was applied to consider the full probabilistic range of values given to the different variables. The goal of this study was to determine, for the studied cases, the levelised cost of energy (LCOE) and the internal rate of return by considering realistic values of the variables. A success rate parameter was calculated, which determined the likelihood of the number of times that the LCOE was below the retail cost of electricity. All the cases were evaluated by applying 10,000 iterations, considering the standard deviations and means defined.

Keywords: photovoltaic (PV) tariffs; remuneration policies; grid parity

1. Introduction

When grid parity for photovoltaic (PV) installations is achieved, all the generated electrical energy can be sold at the same cost at which it is purchased from the grid [1]. To study properly how grid parity can be achieved, several aspects need to be taken into account, such as the possible subsidies or special economic regimes of the PV generators and the financing costs of this type of installation.

With regard to possible special economic subsidies or economic regimes of PV plants, as part of the ongoing challenge to achieve targeted carbon emission reductions set by European countries, governments in Europe introduced in some cases a mechanism for incentivising renewable energy production via the use of the feed-in tariff (FiT) [2]. From its introduction until now, the FiT has endured modifications with respect to political, economic, social and technological (PEST) matters. Due to the lucrative and stable nature of the FiT, private investors have deployed vast interest and investments [3]. The pricing structure that the FiT offers is vital in determining the growth rate of the PV industry and the investments made by private investors and the government, and therein lies the future of the industry [4]. It is important to note that PV is placed firmly as one the most encouraged sources of energy generation [5], where profitability ratios, financial conditions, and the quantification of risks are all clearly defined [6]. This is most advantageous compared to the current fluctuating economy [7]. In addition, the inclusion of batteries can improve the profitability of grid-connected PV installations if the tariff policy allows optimising revenues by managing the charge and discharge of the batteries [8–11]. In the case of Spain, since the introduction of the FiT in 2007 [12], rising financial matters and the ever-changing energy policies have caused unreliability within the sector, hence causing Spain to revoke its FiT in 2012 [4]. Following the decision to revoke the FiT, energy consumption in Spain declined, leading to a significant electricity cost increase, so that independent power generation became an attractive concept due to its financial savings and stability [1].

With regard to financing the costs of PV plants, the levelised cost of energy (LCOE) can be used to calculate the required system and finance expenses necessary to achieve grid parity [13,14]. It is important to keep in mind that financial costs have a significant influence on the LCOE calculation. To take into account the effect of financing costs, the risk of the investment [6] would have to be built into the interest rate [15]. The LCOE is not the same as the electricity cost, but it is used as a proxy for the total price paid by consumers while considering as many realistic costs as possible. When assessing LCOE against grid parity, all system and project costs should be taken into account. These costs include PV modules, structures, inverters, cables and installation.

In this paper, PV grid parity in Spain is studied, calculating the floor of the LCOE (worst-case scenario) for different cases and obtaining conclusions about the cost of the PV system and evaluating the effect of the financing costs [13] on PV grid parity.

In addition, the LCOE and internal rate of return (IRR) are calculated by using the Monte Carlo method [16], giving probabilistic ranges to all of the variables. This methodology allows us to obtain the probability of the possible scenarios. Other authors have used the Monte Carlo method to study a wide variety of realistic problems. The Monte Carlo method has been applied in several previous works in the field of renewable energy generation [17–19], where LCOE and IRR have been used as common economic evaluation tools. Therefore, the tools used in the work presented in this paper are appropriate because they are used routinely in previous work carried out by other authors, obtaining excellent results.

The approach and methodology shown in this work is completely new, as it allows an examination of the effect of financing costs on PV grid parity from a realistically point of view for a wide area (Spain in this case). The methodology used is easily applicable to other countries by adjusting the economic and energy parameters.

2. Materials and Methods

2.1. Costs of a Photovoltaic Installation

To obtain an accurate analysis, all system costs are kept up to date, as any variation can cause significant changes in the results. The total installed PV system cost includes the modules, inverter, support structure, electrical circuits and protections, the cables and structure anchor, as well as the engineering, the mechanical and electrical installation, and value-added tax (VAT).

It is important to note that the depreciation values of components are not considered except for solar modules, hence the costs of all other components are fixed except for that of PV modules. For this reason, in our probabilistic calculation the cost of each component, except the cost of the PV panels, is considered by means of a constant probability density function (PDF), where it changes depending on the three sizes of installation considered in this study (500 kW, 50 kW and 5 kW).

2.1.1. Solar Modules

In the past five years, the system costs decreased to as much as 25% of their initial cost [14]. From 2009 to 2014, the cost of the PV panels decreased by 75% [20]. In September 2012, the European Commission started an antidumping investigation into solar panel imports from China and their key components (wafers and cells). In international trade, dumping is defined as charging a lower price in an export market than is charged in the home country of the producer. It is seen as an anticompetitive strategy aimed at capturing market share in the export market using profits made in the domestic market. Companies that import directly from China, such as distributors, large-scale solar installers and investors, have to provide a bank guarantee for 11.8% of the customs-cleared value of the invoice from 6th June to midnight 5th August on all Chinese manufacturers, and between 37.3% and 67.9% from 6th August, dependent on the Chinese manufacturer [21]. Due to current antidumping charges and legislation imposed by the European Union, it is not possible to assume a lower cost for Chinese-manufactured solar panels [22]. However, some manufacturers have moved factories out of the minimum import (MIP) cost area, and they are offering panels at a price below the MIP. So, the scenario considered in the present study of buying panels from these manufacturers is likely.

The size of the installation directly impacts the cost of the panels. As a result of our benchmark, in May 2015, the cost per Wp to install a 6 kWp/5 kWn (PV panel peak power/inverter nominal power: 6 kW peak/5 kW nominal) grid-connected PV system mounted on a rooftop was 3 €/Wp, and the cost of a single solar module was 1.5 €/Wp. The solar module cost for a single solar module was around 0.8 €/Wp in 2018. This means that the cost per Wp to install a 6 kWp/5 kWn grid-connected PV system mounted on a roof was below 2 €/Wp. For a 50 kWp ground-mounted grid-connected PV system, the cost was 2 €/Wp, and the cost of a single solar module was 1 €/Wp. In 2018, the solar module cost was around 0.6 €/Wp. This means that the cost per Wp to install a 60 kWp/50 kWn grid-connected PV system mounted on a roof top is below 1.2 €/Wp. For a 500 kWp ground-mounted grid-connected PV system, the cost was 1.5 €/Wp, and the cost of a single solar module was 0.8 €/Wp. In 2018, the solar module cost was set at 0.4 €/Wp, which means that the cost per Wp to install a 600 kWp/500 kWn grid-connected PV system on a rooftop was below 0.8 €/Wp.

The PDF used for the cost of solar modules is log-normal with a range between 1 €/kWp and 0.2 €/kWp, and, depending on the size of the installation (500 kWn, 50 kWn and 5 kWn), the mean is determined by the costs described above, set as the current-day cost. The choice of this PDF is suitable for representing the cost of a power generation installation [18]. In this case, taking into account that we only consider uncertainty in the cost of the panels, it is logical to use this PDF to represent its cost.

2.1.2. Mounting Structures

The cost of mounting structures varies depending on the materials selected for the project, such as hot galvanised steel or aluminium. For example, aluminium structures were priced at 0.34 €/Wp. This cost has decreased by 50% over the past few years because aluminium was more than 50% cheaper in 2016 than in 2007 [23].

The cost of the mounting system is considered in our probabilistic calculation using a constant PDF, considered as fixed cost, where it depends on the three sizes of installation (500 kW, 50 kW and 5 kW).

2.1.3. Inverters

Solar inverters convert the DC energy generated from solar panels into AC electricity that is compatible with the AC voltage used in a home or business. A string inverter is the most common type of inverter in the market, and it is likely to be quoted by most small-to-medium-scale solar installation businesses. A microinverter is another type of inverter that is generally more expensive and not as common in the marketplace at the moment. The inverter selection is one of the most important aspects in any solar installation, and the cost of this component can be reduced if adequate analysis is made in selecting its correct size. For a 1 MW inverter, the market offers solutions of around 0.1 €/W. A quick market survey revealed a single inverter of 5 kW from a European manufacturer can be obtained at ~1200€, hence at a cost of 0.24 €/Wn.

The cost of the inverter was modelled using a constant PDF, and it was built into the installation costs. It changes across the three different cases (500 kW, 50 kW and 5 kW).

2.1.4. Operation and Maintenance

The operation and maintenance cost (*OM*) of an electric power generation system can generally be considered as the sum of a fixed part and a variable part, but in the case of PV installations the variable part can be considered equal to zero [24,25]. In this work the annual fixed *OM* costs are calculated by using Equation (1).

$$OM = 19.15 \cdot Peak\ Power \quad (1)$$

where the factor 19.15 has been estimated from the data published by the United States Department of Energy [24] and Fu et al. [25]. The units of this factor are €/kWp. This factor can be considered adequate, since it is based on economic studies of real PV installations [24,25]. *Peak Power* is the peak power of the PV system. The *OM* cost is modelled using a constant PDF, and it is built into the installation costs. It changes across the three different cases (500 kW, 50 kW and 5 kW).

2.2. Annual Energy Production

Before considering the peak power of the installation, the amount of electricity that can be produced by PV panels must be calculated. The amount of electricity produced by a panel is measured in kWh. These units are the same as the units on an electricity bill and are therefore directly comparable; the other unit that is often referred to when discussing output performance is the irradiation, which is the amount of energy from sunlight that hits the surface of a solar panel during a specified time. It is generally measured in kilowatt hours per square metre (kWh/m^2). Irradiance is the power of the sunlight, usually measured in kW/m^2.

The PV panel power and, therefore, the PV system power (composed of several serial and/or parallel panels), is measured in terms of peak power using the unit Wp (watts of peak power), which is the power produced when the irradiance is 1 kW/m^2 in specific conditions. The nominal power of the PV system is usually considered as the nominal power of the inverter. Generally, the nominal power of the system (inverter power) is ~20% lower than the peak power of the system (peak power of the PV panels).

The PV array power is usually oversized relative to the inverter nominal power, achieving a lower cost of delivered energy (€/kWh), but if this DC-to-AC ratio is too high, then a significant amount of generated energy will be lost by clipping losses. When the DC input power of an inverter exceeds its AC output power, saturation losses occur (clipping losses). The ratio between the peak power of the panels and the nominal power of the inverter has been considered in this work is equal to 1.2, which is commonly recommended for the design of PV systems because it results in low clipping losses. Several studies verify that for values up to 1.2 the clipping losses are negligible [26,27]. On the other hand, grid-connected inverters usually have to work with a power factor equal to the unit [28,29], so the PV system only generates active power.

The annual energy production (E), in kWh, is calculated by Equation (2):

$$E = Annual\ Yield \cdot Peak\ Power \tag{2}$$

In Equation (2), *Annual Yield* is the annual energy generated by the PV system per kWp of peak power. This figure varies based on location, the tilt and azimuth angle of the panels and the sun-tracking system. For optimal tilt angle and no tracking system it varies from 1100 kWh/kWp in the north of Spain to 1500 kWh/kWp in the south of Spain. In this case, we define a whole range of annual yield from 1100 kWh/kWp to 1500 kWh/kWp. In our case, a fixed structure is considered, without trackers and with a tilt angle of the panel of 35° (average optimal tilt angle in Spain to maximise the total energy produced in the year). *Peak Power* is the peak power of the PV system. It is usually set as 20% more than the nominal power (inverter).

The PDF considered for the annual yield is a normal one with a range between 1100 and 1500 kWh/kWp. The mean is set at 1300 kWh/kWp, and from this set point the standard deviation is applied. This allows us to survey different locations between the ranges and to apply the annual yield throughout all the cases regardless of the power installed. Given this, we believe that we are representing a wider and realistic range of cases. This approach is applied for the three cases studied (500 kW, 50 kW and 5 kW). In Figure 1, the PDF for the yield used in this work can be observed.

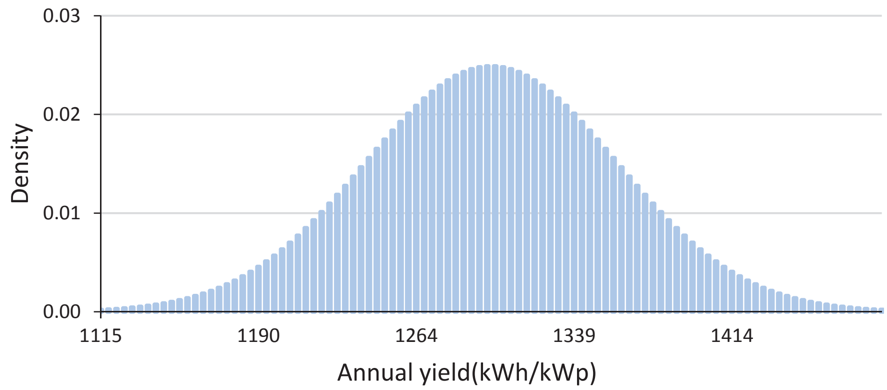

Figure 1. Probability density function (PDF) of the annual yield used in the Monte Carlo probabilistic method.

The use of this distribution is justified because sometimes some variables have a distribution that may not seem normal, this is usually due to the fact that the available historical data are not sufficient [17]. According to the central limit theorem [30], the distribution of a sample is approximately normal if the sample size is large enough. Therefore, in cases such as ours, where we wish to represent the probability density distribution of a variable that depends on multiple factors and is valid to represent the annual yield of the entire Iberian Peninsula, it is justified the use of a normal distribution. As confirmation that the choice of PDF is adequate, Killinger et al. [31] conducted a study that determined the distributions corresponding to the annual yield in several countries, and although differences between them are appreciable, it is observed that a normal distribution would be valid for all of them.

2.3. Economic Parameters Used in the Study

2.3.1. Levelised Cost of Energy

Different calculation methods can be used to determine the *LCOE* [14]. This is determined by the electricity remuneration system [32]. This work uses the Equation (3) [33] to calculate the *LCOE* (€/kWh):

$$LCOE = \frac{(\alpha \cdot I + OM)}{E} \tag{3}$$

where α. is the capital recovery factor, defined later in Section 2.3.2 (dimensionless parameter); *OM* is the annual operation and maintenance cost (€); *I* is the initial investment (€); and *E* is the annual energy production (kWh).

The *LCOE* drives our conclusions [16]. It is calculated depending on the interest rate (*r*), operation and maintenance (*OM*) cost and energy production (E). Therefore, it comprises all the variables and PDFs defined.

2.3.2. Capital Recovery Factor

In Equation (4), the simple Capital Recovery Factor calculation [33] is defined, which is a dimensionless parameter:

$$\alpha = \frac{r}{1 - (1 + r)^{-L}} \tag{4}$$

where *r* is the interest rate (percentage) and *L* is the lifetime of the system (years).

Obtaining a loan can be quite complicated in some countries like Spain (with relatively high interest rates of ~10%) [32]. Due to the financial issues encountered in Spain and the retroactive changes in the PV law over the past few years, the average interest rate rose to 10%. In this paper, the likely interest rates are considered at 6%. However, this figure is considered a variable parameter.

The interest rate is driven by a triangular PDF [18], with 4% being the lowest value and 12% the highest value. The mean would be 6% [4], where most of the loan cases provided by the banks are likely going to be. All this data has been extracted from online loan comparison research. The floor established is stated at 4% in the research, and it is very difficult to see values below this number. The maximum values have been established at 12% as values above that number are considered nonattractive (negative IRRs). Establishing the mean at 6%, the shape of the triangular PDF looks scalene, giving more cases above 4% than below [32]. For IRR calculation purposes, we consider the 12-year loan as standard.

In Figure 2, we can see the triangular PDF of the interest rate.

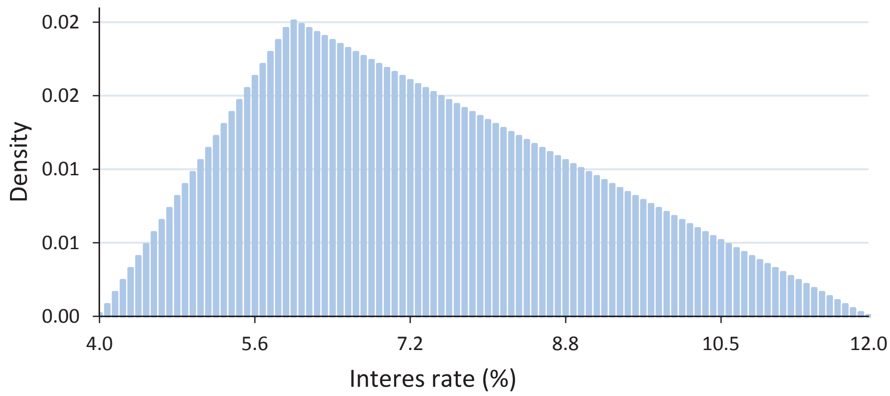

Figure 2. Probability density function (PDF) of the interest rate used in the Monte Carlo method.

Table 1 shows the capital recovery factor values calculated, manually, using Equation (4) for various interest rates. The lifetime of the system is 25 years.

Table 1. Capital Recovery Factor calculation.

Interest rate (%)	12	10	8	6	4
Recovery factor (α)	0.1275	0.1102	0.0937	0.0782	0.0640

The value of the Capital Recovery Factor varies depending on the interest rate (r). The latter applies to the three cases studied, as the PDF of the financial cases are the same regardless of the system power and the energy production.

Applying the Monte Carlo method and using the triangular PDF of the interest rate (Figure 2), we obtained the histogram corresponding to the recovery factor shown in Figure 3. We calculated 10,000 iterations.

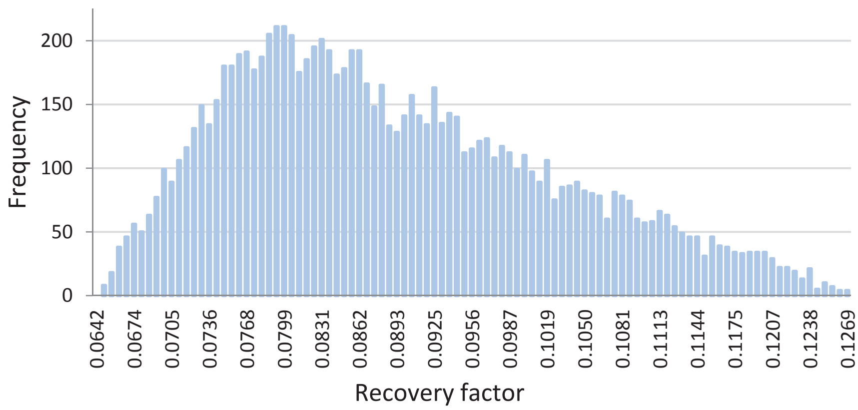

Figure 3. Histogram of the annual recovery factor used in the Monte Carlo method.

A summary of the PDFs of all the variables described previously is shown in Table 2.

Table 2. PDFs used in the Monte Carlo calculation.

Inputs	PDF	Range	Unit
Power	Constant value	6–600	kWp
Lifetime of the system	Constant value	25	Years
Annual Yield	Normal	1100–1500	kWh/kWp
Capital expenditure	Log-normal	0.2–1	€/Wp
Interest rate	Triangular	4–12	%
Retail cost	Constant	0.174	€/kWh

Because the model used in this work is based on the FiT, the lifetime of the project was assumed to be 25 years, as this also coincides with the modules' 25-year warranties.

Table 3 presents the initial investments required in construction of a 6 kWp PV system (5 kW nominal power), considering all system losses.

Table 3. Cost of a PV system at 6000 Wp (5000 W inverter).

	PV Module Cost (€/Wp)				
	1	**0.8 ***	**0.6**	**0.4**	**0.2**
PV module (6 kWp)	6000	4800	3600	2400	1200
Fixed installation costs	6780	6780	6780	6780	6780
TOTAL PV installed cost (€)	12,780	11,580	10,380	9180	7980
VAT (21%)	2684	2432	2180	1928	1676
TOTAL PV installed cost, including taxes (€)	15,464	14,012	12,560	11,108	9656
Total specific cost (€/Wp)	2.58	2.34	2.09	1.85	1.61
Total specific cost (€/W)	3.09	2.80	2.51	2.22	1.93

* Current case.

2.3.3. Internal Rate of Return

The *IRR* is a metric used in the capital budget to estimate the profitability of the potential investments [34]. The *IRR* is a discount rate that makes the net present value (*NPV*) [35] of all cash flows of a project zero [15].

The *IRR* with a loan is much higher than the *IRR* without a loan because a loan at a relatively low interest rate favours the *IRR*. The *IRR* with a loan assumes that the project has a financing scheme typical of the PV industry [4].

The *IRR* calculation procedure is based on determining which *IRR* value results in the *NPV* being zero, as shown in Equation (5):

$$NPV = \sum_{t=1}^{n} \frac{F_t}{(1 + IRR)^t} - I = 0 \quad (5)$$

where F_t is the cash flow during the year t, n is the number of years of the investment and I is the initial investment (€).

The *IRR* was calculated using the interest rate (r), operation and maintenance (OM) cost, annual energy production (E), tax rate (20%) and loan length (12 years), therefore it comprises all the variables and PDFs defined previously.

The sale price of energy was considered equal to the regulated tariff for low-power consumers, in Spain, who do not want to negotiate with the manufacturers. In this work we assumed a regulated tariff of 17.4 c€/kWh, including taxes [1].

3. Results

The cases studied are based on the different annual yields that Spain has, which fit in a range between 1100 and 1500 kWh/kWp. The power of the generator is another variable used as the scaled economy impacts directly on the cost of the panels and installation, which means the grid parity point is affected. Cases of 5 kW, 50 kW and 500 kW of nominal power are considered.

3.1. 5 kW Case Study

First, the deterministic calculation of the LCOE was performed (without considering the PDFs). Thus, it was possible to obtain the most unfavourable case for all the variables that can be used to perform a sensitivity analysis. The aim of this calculation, considering pessimistic values, was to set a conservative scenario that can define a minimum value for the LCOE.

Table 3 shows the costs and taxes, previously described, for a 5 kW system.

The fixed costs used are the support structure, priced at 1700 €; inverter, priced at 1200 €; electrical circuits and protections, priced at 800 €; other materials (cables, anchor and so on), priced at 500 €; mechanical installation, priced at 1620 €; and electrical installation and engineering, priced at 960 €. All of these fixed installation costs total 6780 €.

In Table 3, five case studies are considered; four of them are theoretical and one is a practical case. The cost at 0.8 €/Wp is the current scenario. Although the market could raise its panel costs, the market tendency shows a continuous cost reduction and reaches the other theoretical scenarios shown in Table 1 at costs of 0.6 €/Wp, 0.4 €/Wp and 0.2 €/Wp. Nevertheless, the scenario of 1 €/Wp was also considered.

3.1.1. Levelised Cost of Energy (LCOE)—Calculation Method Analysis for 5 kW and 1100 kWh/kWp Cases

Introducing all the previous parameters and fixing the regulated tariff at 17.4 c€/kWh including taxes and with a fixed interest rate of 10% produces the following results (Table 4), considering an energy production of 6600 kWh/yr, OM annual costs of 114.9 € and a lifetime for the installation of 25 years. The recovery factor value results as 0.1102.

Table 4. Comparison of levelised cost of energy (LCOE) and internal rate of return (IRR) based on a recovery factor at 10% interest, for the 5 kW case.

PV Module Cost (€/Wp)	System Cost (€)	LCOE (€/kWh)	IRR (%)
1	15,464	0.2756	−4.811
0.8	14,012	0.2514	−3.83
0.6	12,560	0.2271	−2.68
0.4	11,108	0.2029	−1.31
0.2	9656	0.1787	0.40

With the results obtained for the LCOE, it can be concluded that Spain would reach grid parity under conditions where the PV modules cost below 0.2 €/Wp. However, the IRR calculated at 25 years with a standard loan of 10% reaches positive values at 0.2 €/Wp. This is because inflation affects the retail electricity cost and changes the LCOE along with time, from beyond to above.

Figure 4 illustrates a clear presentation of the point at which the retail costs and generation costs reach an equilibrium. As we can see, a considerable deviation affects the grid parity forecast.

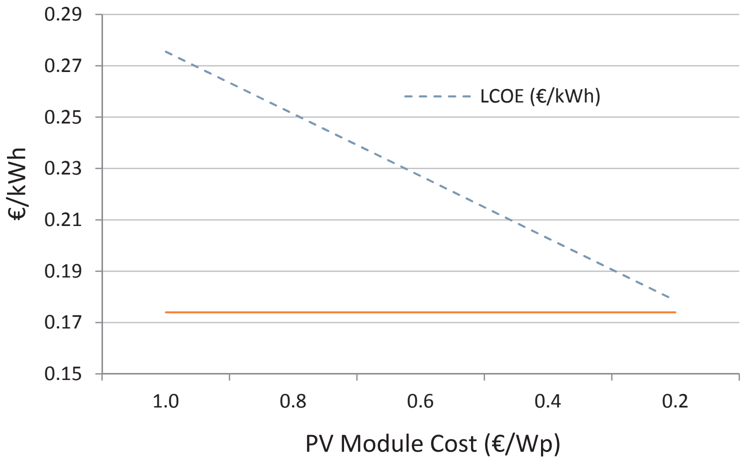

Figure 4. Analysis of the levelised cost of energy (LCOE) against the retail electricity cost at a fixed interest rate of 10% (5000 W inverter, deterministic method).

This case was analysed by introducing a sensibility analysis based on different interest rates to determine which loan terms and conditions allow the system to achieve the retail electricity cost target for grid parity for a different module cost (€/Wp), as shown in Table 5. The positions where the LCOE is lower than the retail cost of energy have been highlighted.

Table 5. LCOE over a range of interest rates (5000 W inverter, deterministic method).

PV Module Cost (€/Wp)	System Cost (€)	LCOE (€/kWh)					
		Interest Rate (%):	12	10	8	6	4
1.0	15,464		0.3161	0.2755	0.2369	0.2007	**0.1674**
0.8	14,012		0.2881	0.2513	0.2163	0.1835	**0.1533**
0.6	12,560		0.2600	0.2270	0.1957	**0.1663**	**0.1392**
0.4	11,108		0.2320	0.2028	0.1751	**0.1491**	**0.1251**
0.2	9656		0.2039	0.1786	**0.1545**	**0.1318**	**0.1110**

Figure 5 shows a graphical representation of the Table 5 results against the retail cost of electricity.

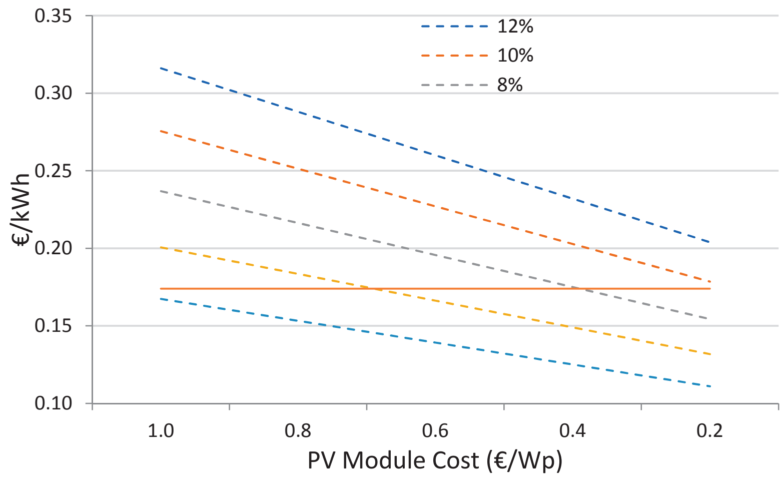

Figure 5. Analysis of the LCOE against the retail electricity cost at various interest rates (5000 W inverter, deterministic method).

3.1.2. 5 kW Case Study Sensibility Analysis

For the 5 kW case study a sensibility analysis was performed considering a range of annual yields from 1100 to 1500 kWh/kWp with a step of 100 kWh/kWp in the range. Using the methodology applied in Section 3.1.1, it is possible to calculate the LCOE by considering the method described previously, fixing the regulated tariff at 17.4 c€/kWh including taxes and with a fixed interest rate of 10%.

Table 6 shows the most relevant results for the five cases. Case 1 corresponds to 1100 kWh/kWp and Case 5 corresponds to 1500 kWh/kWp. The positions where the LCOE is lower than the retail cost of energy have been highlighted.

Table 6. Comparison of the LCOE based on the different annual yield for 5 kW (deterministic method).

			LCOE (€/kWh)				
PV Module Cost (€/Wp)	**System Cost (€)**	**Annual Yield (kWh/kWp):**	**Case 1 1100**	**Case 2 1200**	**Case 3 1300**	**Case 4 1400**	**Case 5 1500**
1.0	15,464		0.276	0.254	0.236	0.220	0.207
0.8	14,012		0.251	0.232	0.215	0.201	0.189
0.6	12,560		0.227	0.210	0.195	0.182	**0.171**
0.4	11,108		0.203	0.187	**0.174**	**0.163**	**0.153**
0.2	9656		0.179	**0.165**	**0.154**	**0.144**	**0.136**

Five case studies are considered in Table 3, but we consider the cost at 0.8 €/Wp as the current scenario. For that reason, the PDF for the panel cost is log-normal with a mean of 0.8 (€/Wp) and a standard deviation of 0.2 (€/Wp). The panel cost floor is set at 0.2 (€/Wp) so that 95% of the cases are represented in the PDF (Figure 6).

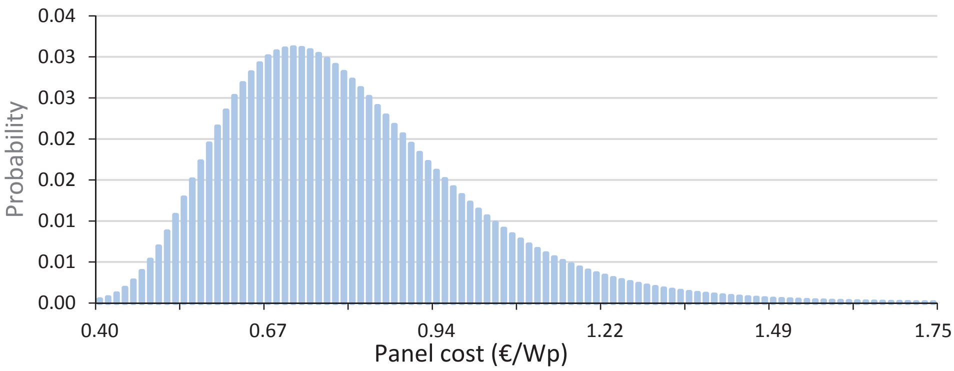

Figure 6. PDF of panel cost for a 5 kW system.

Introducing all the variables in the probabilistic analysis with the Monte Carlo method delivers a wide range of results, giving the following representation (Figure 7), with the frequency of the LCOE above and below the retail electricity cost.

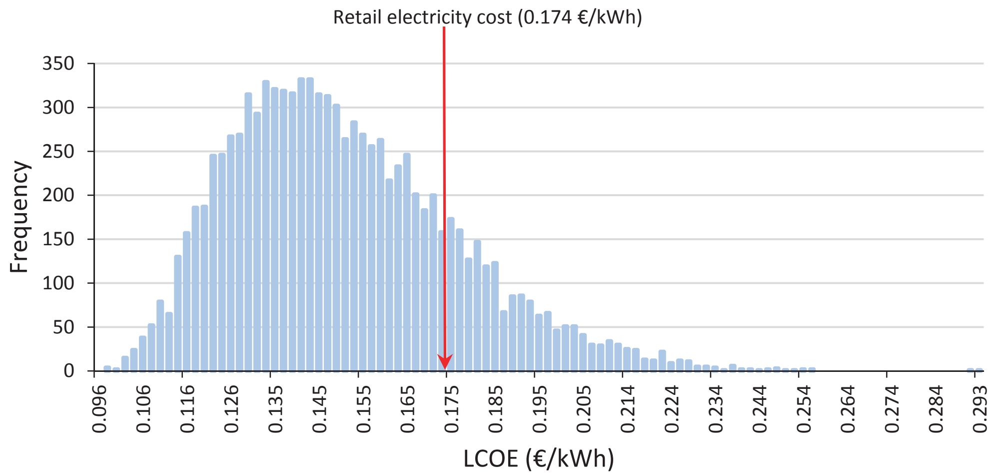

Figure 7. Histogram of the LCOE calculated with the Monte Carlo method for a 5 kW system.

Introducing the results of the iterations given by the Monte Carlo method for the business model, we obtain the IRR values. The IRR results for the 5 kW business case are shown graphically in Figure 8.

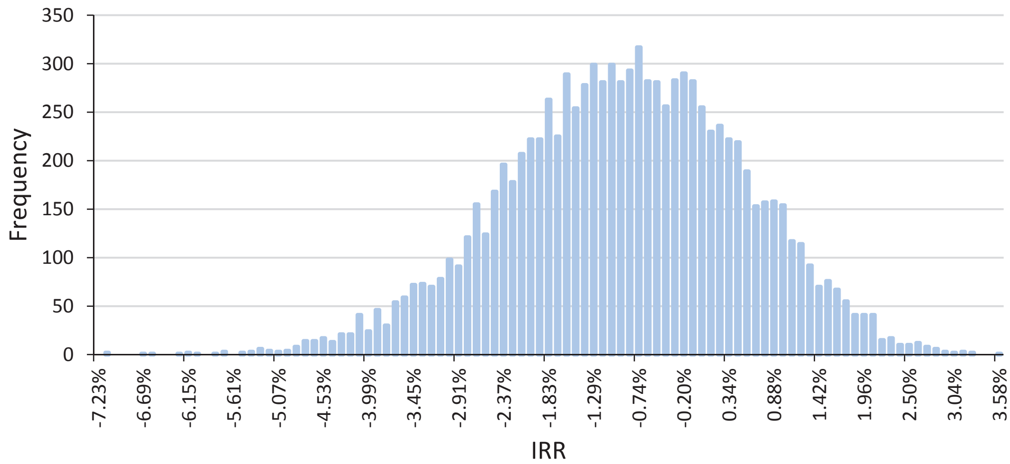

Figure 8. Histogram of the internal rate of return (IRR) calculated with the Monte Carlo method for a 5 kW system.

A success rate parameter (%) is introduced by counting the number of iteration results below the retail cost of the electricity and dividing by the total number of iterations (10,000). By analysing the frequency of the results and the value itself, the success rate can be calculated for each case. In the case of a 5 kW installation, the success rate would be 82.26%. This means that in 82.26% of cases, grid parity is achieved, as the LCOE is lower than the retail cost. However, as a business case, the mean of the IRR is negative (−0.97%). Therefore, it can be concluded that the loan input in the model contributes negatively to the success of the investment.

3.2. 50 kW Case Study

The manual calculation of the LCOE takes the worst-case scenario to set a conservative scenario that can define a floor. In Table 7 below, the fixed costs are represented (variable costs and taxes described in previous points) for a 50 kW system.

Table 7. Cost of a PV system at 60,000 Wp (50,000 W inverter).

	PV Module Cost (€/Wp)				
	1	**0.8**	**0.6 ***	**0.4**	**0.2**
PV module (60 kWp)	60,000	48,000	36,000	24,000	12,000
Fixed installation costs	38,000	38,000	38,000	38,000	38,000
TOTAL PV installed cost (€)	98,000	86,000	74,000	62,000	50,000
VAT (21%)	20,580	18,060	15,540	13,020	10,500
TOTAL PV installed cost, including taxes (€)	118,580	104,060	89,540	75,020	60,500
Total specific cost (€/Wp)	1.98	1.73	1.49	1.25	1.01
Total specific cost (€/W)	2.37	2.08	1.79	1.50	1.21

* Current case.

The fixed costs used are the support structure, priced at 9000 €; inverter, priced at 8000 €; electrical circuits and protections, priced at 2000 €; other materials (cables, anchor and so on), priced at 5000 €; mechanical installation, priced at 6000 €; and electrical installation and engineering, priced at 8000 €. These fixed installation costs come to a total of 38,000 €.

A worst-case scenario can be assumed for a 50 kW system as shown in Table 7 [4].

Five case studies are considered in Table 7: four of them are theoretical and one is a practical case. The cost at 0.6 €/Wp is the current scenario. Although the market could raise its panel costs, the market tendency shows a continuous cost reduction and reaches the other theoretical scenarios shown in Table 7 at costs of 0.4 €/Wp and 0.2 €/Wp. The scenarios of 0.8 €/Wp and 1 €/Wp are also considered.

3.2.1. LCOE—Calculation Method Analysis for 50 kW and 1100 kWh/kWp Case

Introducing all the previous parameters and fixing the regulated tariff at 17.4 c€/kWh including taxes and with a fixed interest rate of 10% produces the following results (Table 8), considering an energy production of 60,600 kWh/yr, OM annual costs of 1149 € and a lifetime for the installation of 25 years. The recovery factor value results as 0.1102.

Table 8. Comparison of LCOE and IRR based on a recovery factor at 10% interest for the 50 kW case.

PV Module Cost (€/Wp)	System Cost (€)	LCOE (€/kWh)	IRR (%)
1	118,580	0.2154	−2.049
0.8	104,060	0.1911	−0.53
0.6	89,540	0.1669	1.39
0.4	75,020	0.1427	3.97
0.2	60,500	0.11841	7.46

With the results obtained for the LCOE, it can be concluded that Spain would reach grid parity under conditions where the PV modules cost between 0.8 €/Wp and 0.6 €/Wp. The IRR calculated at 25 years with a standard loan of 10% reaches positive values at between 0.8 €/Wp and 0.6 €/Wp. It is concluded that there is a floor of 1.39% of IRR for the current panel cost scenario and the worst-case scenario of yield and interest rate.

Figure 9 illustrates a clear presentation of the point at which the retail costs and generation costs reach an equilibrium. As can be seen, there is a considerable deviation which impacts the grid parity forecast.

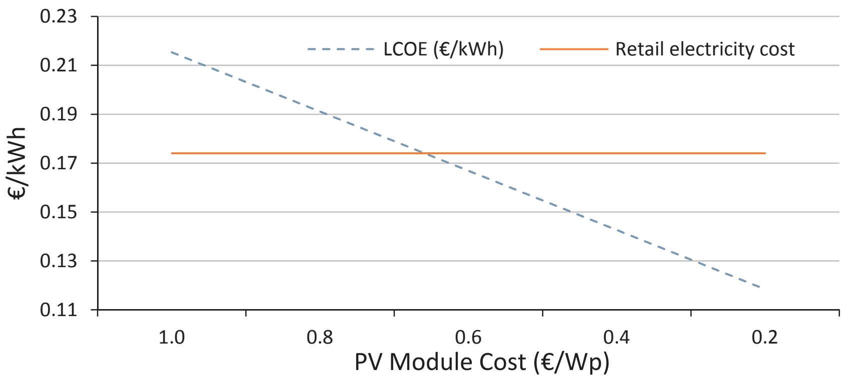

Figure 9. Analysis of the LCOE against the regulated tariff at a fixed interest rate of 10% (50,000 W inverter, deterministic method).

This case is analysed by introducing a sensibility analysis based on different interest rates, determining which loan terms and conditions allow the system to achieve the regulated tariff target for grid parity for a different module cost (€/Wp), as shown in Table 9. The positions where the LCOE is lower than the retail cost of energy have been highlighted

Table 9. LCOE over a range of interest rates (50,000 W inverter, deterministic method).

PV Module Cost (€/Wp)	System Cost (€)	LCOE (€/kWh)					
		Interest Rate (%):	12	10	8	6	4
1.0	118,580		0.2465	0.2153	0.1857	**0.1579**	**0.1324**
0.8	104,060		0.2184	0.1911	**0.1651**	**0.1407**	**0.1183**
0.6	89,540		0.1904	**0.1669**	**0.1445**	**0.1235**	**0.1042**
0.4	75,020		**0.1623**	**0.1426**	**0.1239**	**0.1063**	**0.0902**
0.2	60,500		**0.1343**	**0.1184**	**0.1033**	**0.0891**	**0.0761**

Figure 10 shows a graphical representation of the Table 9 results against the retail electricity cost.

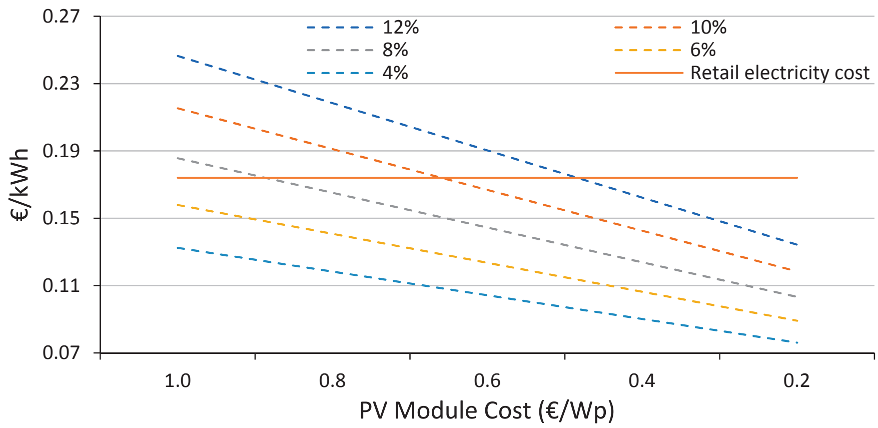

Figure 10. Analysis of the LCOE against the retail electricity cost at various interest rates (50,000 W inverter, deterministic method).

3.2.2. 50 kW Case Study Sensibility Analysis

For the 50 kW case study a sensibility analysis has been performed considering a range of annual yields from 1100 to 1500 kWh/kWp with a step of 100 kWh/kWp in the range. Using the methodology applied in Section 3.1.1, it is possible to calculate the LCOE considering the method described previously, fixing the regulated tariff at 17.4 c€/kWh including taxes and with a fixed interest rate of 10%.

Table 10 shows the most relevant results for the five cases. Case 1 corresponds to 1100 kWh/kWp and Case 5 corresponds to 1500 kWh/kWp. The positions where the LCOE is lower than the retail cost of energy have been highlighted.

Table 10. Comparison of the LCOE based on the different annual yield for 50 kW.

			LCOE (€/kWh)				
PV Module Cost (€/Wp)	**System Cost (€)**	**Annual Yield (kWh/kWp):**	**Case 1 1100**	**Case 2 1200**	**Case 3 1300**	**Case 4 1400**	**Case 5 1500**
1.0	118,580		0.215	0.199	0.185	**0.173**	**0.163**
0.8	104,060		0.191	0.177	**0.164**	**0.154**	**0.145**
0.6	89,540		**0.167**	**0.154**	**0.144**	**0.135**	**0.127**
0.4	75,020		**0.143**	**0.132**	**0.123**	**0.116**	**0.109**
0.2	60,500		**0.118**	**0.110**	**0.103**	**0.097**	**0.091**

Five case studies are considered in Table 7, but the cost at 0.6 €/Wp is considered as the current scenario. For that reason, the PDF for the panel cost is log-normal with a mean of 0.6 (€/Wp) and a standard deviation of 0.2 (€/Wp). The panel cost floor is set at 0.2 (€/Wp) so that the 95% of the cases are represented in the PDF (Figure 11).

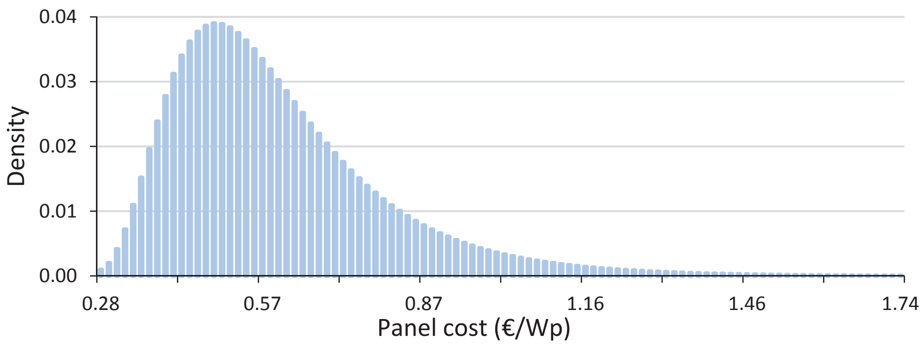

Figure 11. PDF of panel cost for a 50 kW system.

Introducing all the variables in the probabilistic analysis with the Monte Carlo method delivers a wide range of results, giving the following representation (Figure 12) with the frequency of the LCOE above and below the retail electricity cost.

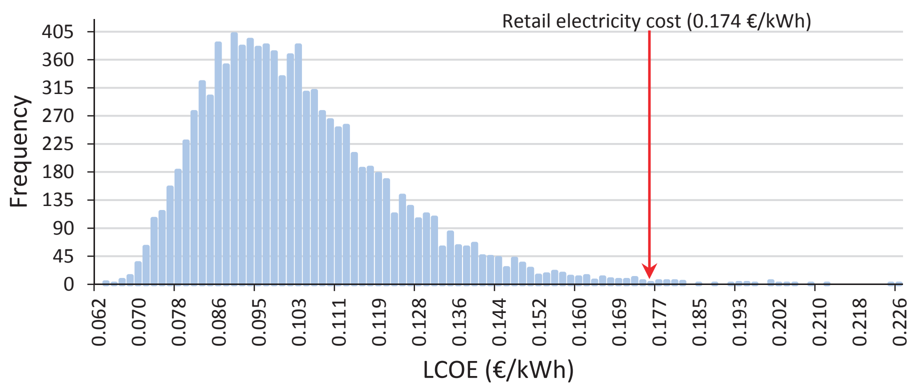

Figure 12. Histogram of the LCOE calculated with the Monte Carlo method for a 50 kW system.

Introducing the results of the iterations given by the Monte Carlo method for the business model, we obtain the IRR values. The IRR results for the 50 kW business case are shown graphically in Figure 13.

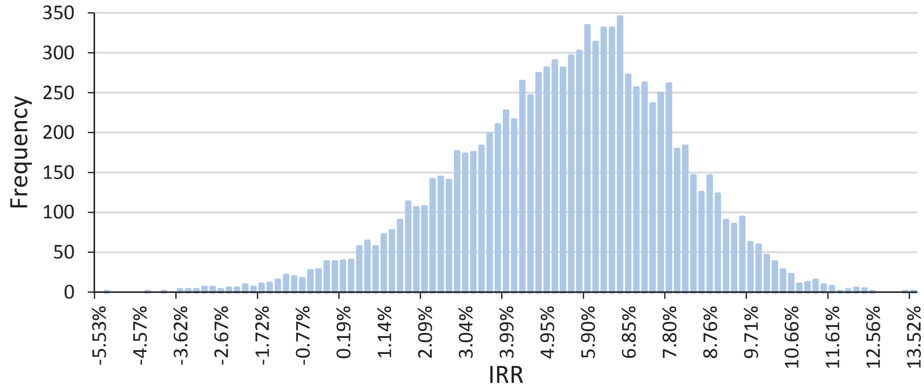

Figure 13. Histogram of the IRR calculated with the Monte Carlo method for a 50 kW system.

A success rate parameter (%) is introduced by counting the number of iteration results below the retail cost of the electricity and dividing by the total number of iterations (10,000). Analysing the frequency of the results and the value itself, the success rate for each case can be calculated. In this case of a 50 kW installation, it can be concluded that the success rate would be 99.59%. This means that in 99.59% of cases, grid parity is achieved as the LCOE is lower than the retail cost. As a business case, the mean of the IRR is positive (5.29%). Therefore, it can be concluded that even though the loan input in the model contributes negatively, the investment is successful.

3.3. 500 kW Case Study

The manual calculation of the LCOE takes the worst-case scenario for all the variables that could influence the sensitivity analysis carried out on this section. The aim of this calculation, considering pessimistic values, is to set a conservative scenario that can define a floor. The table below (Table 11) represents the fixed costs, variable costs and taxes, described in previous points, for a 500 kW system.

Table 11. Cost of a PV system at 600,000 Wp (500,000 W inverter).

	PV Module Cost (€/Wp)				
	1	**0.8**	**0.6**	**0.4 ***	**0.2**
PV module (600 kWp)	600,000	480,000	360,000	240,000	120,000
Fixed installation costs	245,000	245,000	245,000	245,000	245,000
TOTAL PV installed cost (€)	980,000	725,000	605,000	485,000	365,000
VAT (21%)	177,450	152,250	127,050	101,850	76,650
TOTAL PV installed cost, including taxes (€)	1,022,45	877,250	732,050	586,850	441,650
Total specific cost (€/Wp)	1.70	1.46	1.22	0.98	0.74
Total specific cost (€/W)	2.04	1.75	1.46	1.17	0.88

* Current case.

Fixed costs: support structure, priced at 90,000 €; inverter, priced at 40,000 €; electrical circuits and protections, priced at 40,000 €; other materials (cables, anchor and so on), priced at 20,000 €; mechanical installation, priced at 45,000 €; and electrical installation and engineering, priced at 10,000 €. These fixed installation costs come to a total of 245,000 €.

A worst-case scenario can be assumed for a 500 kW system as shown in Table 11 [4].

As we have done previously, five case studies are considered in Table 11: four of them are theoretical and one is a practical case. The cost at 0.4 €/Wp is the current scenario. Although the market could raise its panel costs, the market tendency shows a continuous cost reduction and reaches the other theoretical scenarios shown in Table 11, especially at costs of 0.2 €/Wp; the scenarios of 0.6 €/Wp, 0.8 €/Wp and 1 €/Wp are also considered.

3.3.1. LCOE—Calculation Method Analysis for 500 kW and 1100 kWh/kWp Case

Introducing all the previous parameters and fixing the regulated tariff at 17.4 c€/kWh, including taxes and with a fixed interest rate of 10%, produces the following results (Table 12), considering an energy production of 660,000 kWh/yr, OM annual costs of 11,490€ and a lifetime for the installation of 25 years. The recovery factor value is 0.1102.

Table 12. Comparison of LCOE and IRR based on a recovery factor at 10% interest, for the 500 kW case.

PV Module Cost (€/Wp)	System Cost (€)	LCOE (€/kWh)	IRR (%)
1	1,022,45	0.1585	−0.316
0.8	877,250	0.1385	1.67
0.6	732,050	0.1184	4.36
0.4	586,850	0.0984	8.02
0.2	441,650	0.07834	14.52

With the results obtained for the LCOE, it can be concluded that Spain would reach grid parity under all conditions represented in this paper. However, the IRR calculated at 25 years with a standard loan of 10% reaches positive values between 1 €/Wp and 0.8 €/Wp. It can be concluded that there is a floor of 8.02% of IRR for the current panel cost scenario (0.4 €/Wp) and the worst-case scenario of yield and interest rate.

Figure 14 illustrates a clear presentation of the point at which the retail costs and generation costs reach an equilibrium. As can been seen, there is a considerable deviation impacting the grid parity forecast.

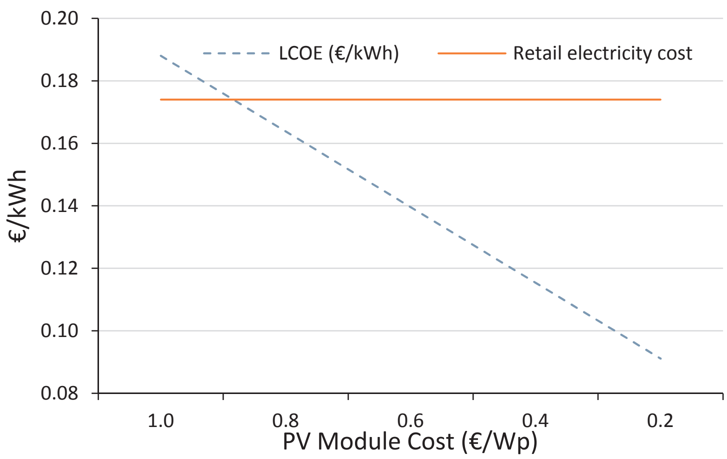

Figure 14. Analysis of the LCOE against the retail electricity cost at a fixed interest rate of 10% (500,000 W inverter, deterministic method).

This case is analysed by introducing a sensibility analysis based on different interest rates, determining which loan terms and conditions allow the system to achieve the regulated tariff target for grid parity for a different module cost (€/Wp), as shown in Table 13. The positions where the LCOE is lower than the retail cost of energy have been highlighted.

Table 13. LCOE over a range of interest rates (50,000 W inverter, deterministic method).

PV Module Cost (€/Wp)	System Cost (€)	Interest Rate (%):	LCOE (€/kWh) 12	10	8	6	4
1.0	1,022,450		0.2149	0.1881	**0.1625**	**0.1386**	**0.1166**
0.8	877,250		0.1869	**0.1638**	**0.1419**	**0.1214**	**0.1025**
0.6	732,050		**0.1588**	**0.1396**	**0.1213**	**0.1042**	**0.0884**
0.4	586,850		**0.1308**	**0.1154**	**0.1007**	**0.0870**	**0.0743**
0.2	441,650		**0.1027**	**0.0911**	**0.0801**	**0.0697**	**0.0602**

Figure 15 shows a graphical representation of the Table 13 results against the retail cost of electricity.

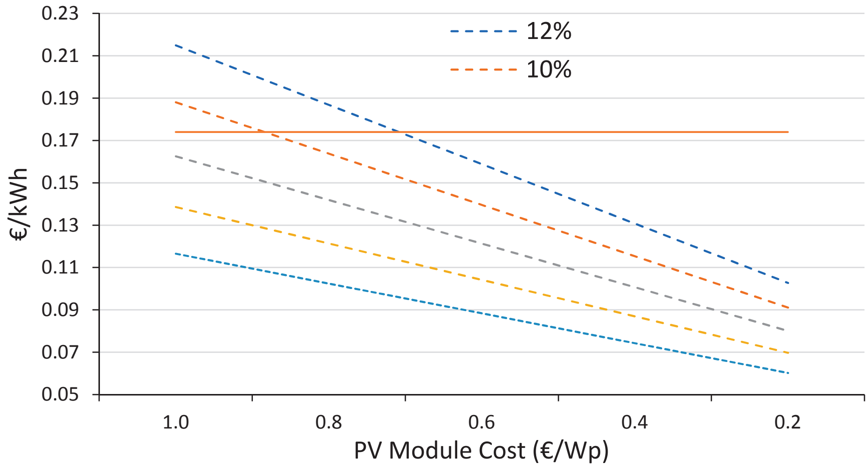

Figure 15. Analysis of the LCOE against the retail electricity cost at various interest rates (500,000 W inverter, deterministic method).

3.3.2. 500 kW Case Study Sensibility Analysis

For the 500 kW case study a sensibility analysis has been performed considering a range of annual yields from 1100 to 1500 kWh/kWp with a step of 100 kWh/kWp in the range. Using the methodology applied in Section 3.1.1, it is possible to calculate the LCOE considering the method described previously, fixing the regulated tariff at 17.4 c€/kWh including taxes and with a fixed interest rate of 10%.

Table 14 shows the most relevant results for the five cases. Case 1 corresponds to 1100 kWh/kWp and Case 5 corresponds to 1500 kWh/kWp. The positions where the LCOE is lower than the retail cost of energy have been highlighted.

Table 14. Comparison of the LCOE based on the different annual yield for 500 kW.

PV Module Cost (€/Wp)	System Cost (€)	Annual Yield (kWh/kWp):	LCOE (€/kWh) Case 1 1100	Case 2 1200	Case 3 1300	Case 4 1400	Case 5 1500
1.0	1,022,450		0.188	0.174	**0.162**	**0.151**	**0.143**
0.8	877,250		**0.164**	**0.152**	**0.141**	**0.132**	**0.125**
0.6	732,050		**0.140**	**0.129**	**0.121**	**0.113**	**0.107**
0.4	586,850		**0.115**	**0.107**	**0.100**	**0.094**	**0.089**
0.2	441,650		**0.118**	**0.110**	**0.103**	**0.097**	**0.091**

Table 11 considers five cases, but the cost at 0.4 €/Wp is considered as the current scenario. For that reason, the PDF for the panel cost is log-normal with a mean of 0.4 (€/Wp) and a standard deviation of 0.2 (€/Wp). The panel cost floor is set at 0.2 (€/Wp) so that 95% of the cases are represented in the PDF (Figure 16).

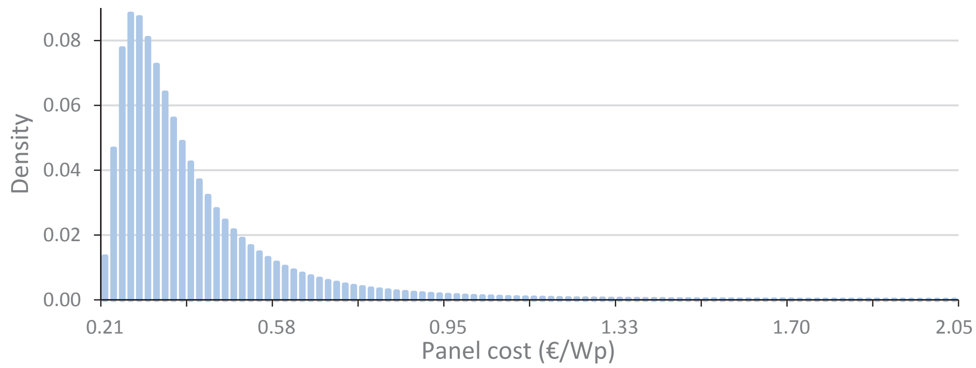

Figure 16. PDF of panel cost for a 500 kW system.

Introducing all the variables in the probabilistic analysis with the Monte Carlo method delivers a wide range of results, giving the following representation (Figure 17), with the frequency of the LCOE above and below the retail electricity cost.

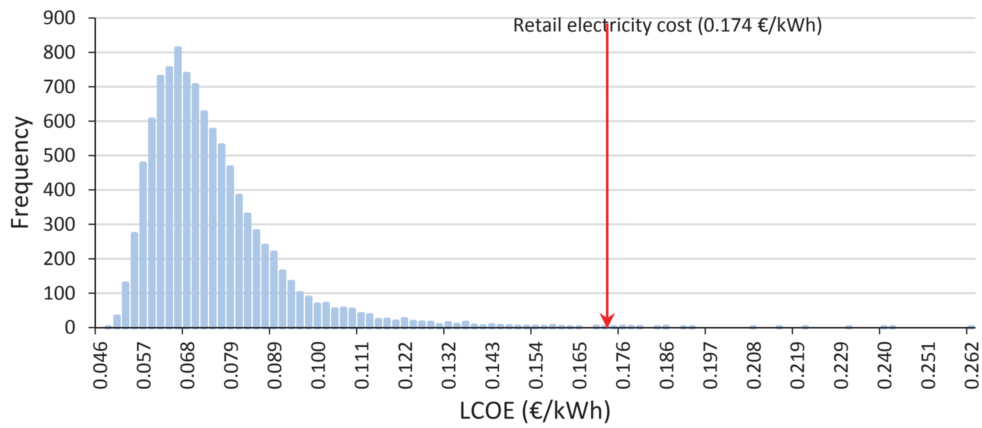

Figure 17. Histogram of the LCOE calculated with the Monte Carlo method for a 500 kW system.

Introducing the results of the iterations given by the Monte Carlo method for the business model, we obtain the IRR values. The IRR results for the 500 kW business case are shown graphically in Figure 18.

A success rate parameter (%) is introduced by counting the number of iteration results below the retail cost of the electricity and dividing by the total number of iterations (10,000). Analysing the frequency of the results and the value itself, the success rate for each case can be calculated. In this case of a 500 kW installation, it has been concluded that the success rate would be 99.80%. This means that in 99.80% of the cases, grid parity is achieved as the LCOE is lower than the retail cost. As a business case, the mean of the IRR is positive (14.34%). Therefore, it can be concluded that even though the loan input in the model contributes negatively, the investment is successful.

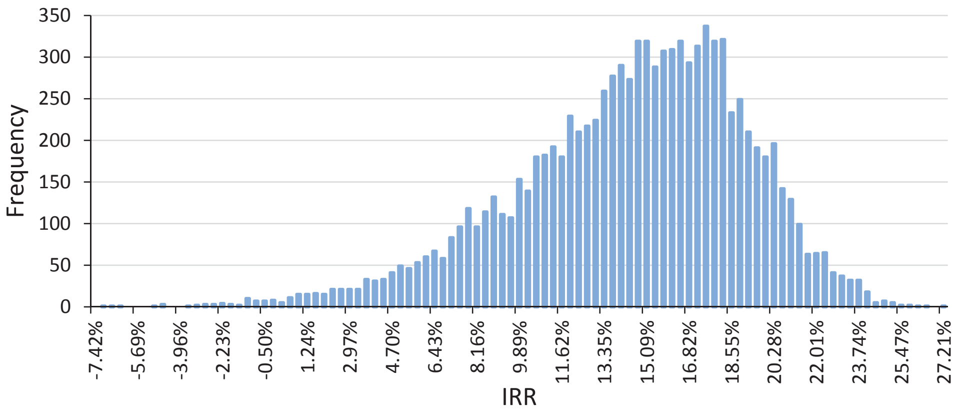

Figure 18. Histogram of the IRR calculated with the Monte Carlo method for a 500 kW system.

4. Discussion

In this paper, the effects of financial cost on PV grid parity are discussed. The study has been carried out using a probabilistic method (Monte Carlo), considering three cases corresponding to three PV installations of different sizes (5 kW, 50 kW and 500 kW of inverter power).

First, for each case, the deterministic calculation of the LCOE is performed; obtaining the most unfavourable case for all the variables that can be used to perform a sensitivity analysis. The aim of this calculation, considering pessimistic values, is to set the minimum value for the LCOE.

The first case corresponds to a PV installation of 5 kW (inverter power). The worst-case scenarios considering a 10% interest rate and a 1100 kWh/kWp yield have been calculated manually (Table 4). With these results, a bottom line can be drawn and considered a floor. In Table 6, a summary of the LCOE for each annual yield is represented. The positions where the LCOE is lower than the retail cost of energy have been highlighted, so we can say that in these conditions, grid parity is already reached. In the deterministic calculation method, it could be determined that the LCOE would reach the retail electricity cost at an interest rate of 4% (Table 5) for any module cost. Table 6 shows that a module cost 0.2 €/Wp in areas with 1200 kWh/kWp (and above) is necessary to achieve grid parity, and in areas with an annual yield of 1300 kWh/kWp (and above), grid parity could be reached with a module cost of 0.4 €/Wp. It can be concluded that for a small installation of 5 kW, grid parity will be achieved if the module cost is between 0.2 and 0.4 €/Wp at a fixed interest rate of 10% in areas from 1200 kWh/kWp and above.

The second case corresponds to a PV installation of 50 kW. This case is summarised in Tables 8–10. In the deterministic calculation method, it can be determined that the LCOE would reach the retail energy cost at the interest rate of 6% for any module cost, but this can also be determined at an interest rate of 10% (Table 9) and a cost between of 0.6 and 0.4 €/Wp and below. Table 10 shows that grid parity in areas with 1400 kWh/kWp (and above) is already achieved in any case. In areas with an annual yield of 1300 kWh/kWp and 1200 kWh/kWp, grid parity could be reached at any cost except with a module cost of 1 €/Wp and a fixed interest of 10%. In areas with an annual yield of 1100 kWh/kWp, grid parity is already achieved for a module cost of 0.6 €/Wp and below. Finally, it can be concluded that for the case of 0.8 €/Wp, grid parity is already achieved for an area with an annual yield of 1200 kWh/kWp and above (Table 10), which in the Spanish case means the majority of the territory.

The third case corresponds to a PV installation of 500 kW. This case is summarised in Tables 12–14. With the deterministic calculation method, it can be determined that the LCOE would reach the retail energy cost at an interest rate of 8% (Table 13) for any module cost, but this can also be determined at an interest rate of 10% and a cost of 0.8 €/Wp and below. Areas with an annual yield of 1200 kWh/kWp and above have already achieved grid parity in any case. In areas with an annual yield of 1100 kWh/kWp, grid parity could be reached at any cost except with a module cost of 1 €/Wp. For a module cost of 0.6 €/Wp and below, grid parity is achieved in any case, so it can be concluded that for the current scenario, grid parity is already achieved (Table 14).

The deterministic calculation methodology allows us to reach several conclusions. In small installations, grid parity will be reached depending on the financial model and the cost of the installation. In middle-scale installations, grid parity is already achieved, except for some geographical cases with an annual yield of 1100 kWh/kWp. Large-scale installations can be connected without any tariff, as the cost of energy is lower than the retail cost of energy at any case.

The probabilistic method (Monte Carlo) has been evaluated precisely for all the variable inputs if grid parity is achieved and how profitable the installation can be as a business. In Table 15, it can be determined when the LCOE is achieved, considering a recovery factor value of 0.1102. The representative cases where the LCOE is lower than the retail cost of energy have been highlighted.

Table 15. Comparison of the LCOE based on the Monte Carlo method for all the cases.

PV Module Cost (€/Wp)	LCOE (€/kWh)		
	5 kW	50 kW	500 kW
1	0.2756	0.2154	**0.1585**
0.8	0.2514	0.1911	**0.1385**
0.6	0.2271	**0.1669**	**0.1184**
0.4	0.2029	**0.1427**	**0.0984**
0.2	0.1787	**0.1184**	**0.0783**

Table 16 shows when the IRR is positive; this means the investment can be considered a business. The representative cases where the IRR is positive have been highlighted.

Table 16. Comparison of the IRR based on the Monte Carlo method for all the cases.

PV Module Cost (€/Wp)	IRR (%)		
	5 kW	50 kW	500 kW
1	−4.81	−2.05	−0.32
0.8	−3.83	−0.53	**1.67**
0.6	−2.68	**1.39**	**4.36**
0.4	−1.31	**3.97**	**8.02**
0.2	**0.40**	**7.46**	**14.52**

Finally, the means applied to the variables can be taken into consideration. These means defining the likelihoods defined across this paper where the panel cost is key to determine the LCOE and the IRR. Table 17 presents a summary that determines the results for the full range of options that we have determined for all the variables, which have been represented across this paper. The success rate represented in Table 17 determines the percentage of how many cases of LCOE have resulted above the retail electricity cost. As can be seen in Table 17, the rate is quite high. However, the financial parameters, such the interest rate, loan duration and amount loaned, significantly impact the IRR.

Table 17. Summary of the means of IRR and LCOE extracted from the Monte Carlo method for all the cases.

Power (kW)	Mean PV Module Cost (€/Wp)	Mean Yield (kWh/kWp)	Mean Interest Rate (%)	Mean LCOE (€/kWh)	Mean IRR (%)	Success Rate (%)
5	0.8	1300	6	0.1494	−0.97	82.26
50	0.6	1300	6	0.1019	5.92	99.59
500	0.4	1300	6	0.0727	14.34	99.80

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Apéndice

Factor de impacto de las revistas y áreas temáticas

Energy policy

Fuente: InCities Journal Citation Reports

Año	Energy & Fuels		Environmental Sciences	
	Posición	Cuartil	Posición	Cuartil
2018	22/103	Q1	35/251	Q1
2017	28/97	Q2	47/242	Q1
2016	19/92	Q1	33/229	Q1
2015	29/88	Q2	59/225	Q2
2014	34/89	Q2	68/223	Q2
2013*	33/83	Q2	62/216	Q2

*C.J. Sarasa-Maestro, R. Dufo-López, J.L. Bernal-Agustín, Photovoltaic remuneration policies in the European Union, *Energy Policy*. 55 (2013) 317–328. doi:10.1016/j.enpol.2012.12.011.

Advanced Materials Research

Fuente: Scopus

Año	Engineering: General Engineering		
	Posición	Percentil	CiteScore
2015	67/148	10th	0,08
2014*	77/146	12th	0,09
2013	75/148	13th	0,11
2012	64/145	15th	0,12
2011	159/227	29th	0,19

*C.J. Sarasa-Maestro, R. Dufo-López, J.L. Bernal-Agustín, Grid Parity Analysis of PV Markets, in: *Advanced Materials Research*, 2014: pp. 441–445. doi:10.4028/www.scientific.net/AMR.827.441.

Energies

Fuente: InCities Journal Citation Reports (Thomson Reuters)

Año	Energy & Fuels	
	Posición	Cuartil
2018	56/103	Q3
2017	48/97	Q2
2016*	45/92	Q2
2015	43/88	Q2
2014	43/89	Q2
2013	43/83	Q3

*C. Sarasa-Maestro, R. Dufo-López, J. Bernal-Agustín, Analysis of Photovoltaic Self-Consumption Systems, *Energies*. 9 (2016) 681. doi:10.3390/en9090681.

Applied Sciences

Fuente: InCities Journal Citation Reports (Thomson Reuters)

Año	Physics, Applied		Chemistry, Multidisciplinary	
	Posición	Cuartil	Posición	Cuartil
2018*	67/148	Q2	*35/251*	Q3
2017	77/146	Q3	*47/242*	Q3
2016	75/148	Q3	*33/229*	Q3
2015	64/145	Q2	*59/225*	Q3
2014	79/144	Q3	*68/223*	Q2

Año	Material Science, Multidisciplinary	
	Posición	Cuartil
2018*	151/293	Q3
2017	171/285	Q3
2016	150/275	Q3
2015	129/271	Q2
2014	139/260	Q3

*C. Sarasa-Maestro, R. Dufo-López, J. Bernal-Agustín, Evaluating the Effect of Financing Costs on PV Grid Parity by Applying a Probabilistic Methodology, *Applied Sciences* 9 (2019) 425. doi:10.3390/app9030425.