THÈSE DE DOCTORAT

de l'Université de recherche Paris Sciences et Lettres
PSL Research University

Préparée à l'Université Paris-Dauphine

ANALYZING THE OPTIMAL DEVELOPMENT OF ELECTRICITY STORAGE IN ELECTRICITY MARKETS WITH HIGH VARIABLE RENEWABLE ENERGY SHARES

École Doctorale de Dauphine — ED 543

Spécialité **Sciences économiques**

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Ecole Doctorale de Dauphine - ED 543
Centre de Géopolitique de l'Énergie et des Matières Premières (CGEMP-LEDa)
Chaire European Electricity Markets (CEEM)

Discipline : Sciences Économiques

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To the memory of Porfi, Lucecita y María.

Thank you for showing me the way

ABSTRACT

The increasing variability of electricity production in Europe, which is mainly due to the intermittent production of renewables such as wind and photovoltaic (VRE), will require significant efforts to reconcile demand and supply at any time. Thus, increasing shares of variable infeed implies increasing the need for system services. Apart from upgraded interconnections, demand-side management (DSM) and dispatchable backup capacity, electric energy storage (EES) technologies will have a major role to play in this context.

However, due to the peculiar price formation mechanism prevailing in energy-only electricity markets, the commercial case for EES is being eroded by the very forces that create the need for its deployment at system level. The private incentives of EES are thus diminishing while its social value, which is determined by the multiple system services these technologies can supply, becomes more important.

This thesis sets out to (1) model and assess the interplays between variability, flexibility needs and decarbonization objectives, (2) analyze the role and the value of EES technologies in view of the French official objectives by 2020, 2030 and 2050, and (3) discuss regulatory aspects, and propose a set of energy policies allowing to succeed in the energy transition and decarbonization goals.

Keywords:

Reneawable Energies, Flexibility, Electricity Storage, Demand-Response, Smart Grids, Capacity Expansion Planing, Investments

RESUME

La pénétration des technologies renouvelables à forte apport variable pose de nombreuses difficultés dans le fonctionnement du système électrique. L'équilibre offre-demande doit être garanti à tout moment, des hauts niveaux de fiabilité doivent être assures. Ainsi, la variabilité accroit les besoins de flexibilité et des services système. Ils existent plusieurs options capables de fournir ces services, dont : le renforcement des interconnections, le pilotage intelligent de la demande, le renforcement des capacités de réponse rapide des unités de production, mais aussi, la mise en œuvre des technologies de stockage de l'électricité. Cependant, les marchés électriques actuels sont basés sur la rémunération de l'énergie. Donc, la valorisation intégrale des services fournis par le stockage semble difficile, ce qui restreint le « business case » des options de flexibilité.

Cette thèse s'inscrit autour des propos suivants : (1) modéliser et évaluer les interrelations entre variabilité, besoins de flexibilité et objectifs de décarbonation du parc électrique, (2) analyser le rôle, ainsi que la valeur, des différents technologies du stockage à travers le cas Français aux horizons 2020, 2030 et 2050, et (3) discuter sur les aspects de régulation de la flexibilité, ainsi que proposer des politique énergétiques concrètes permettant la réussite des objectifs de transition énergétique et de décarbonation du mix électrique.

Mots-clés :

Energies renouvelables, Flexibilité, Stockage de l'électricité, Pilotage de la Demande, Réseaux Intelligents, Investissements

ACKNOWLEDGMENTS

This dissertation would not have been possible without the help and support of many individuals and friends.

First and foremost, I want to thank the members of my doctoral committee: M. Jan Horst Keppler, M. Patrice Geoffron, M. Marco Cometto, M. Frederic Lantz, M. Olivier Massol and M. Erik Delarue.

Prof. Lantz and Massol have introduced me to the exciting field of research in energy economics since the master EDDEE at the IFP-School. Prof. Geoffron and M. Cometto, you have always been available for interesting discussion and for guiding me with all your experience. Exchanging with Prof. Delarue and his team at KU Leuven was particularly inspiring and formative by the beginning of my research. I have enjoyed discussing with all of you along my Ph.D. research, and I have learned a lot from all your individual perspectives, which are extremely rich and complementary. I also thank Dominique Finon, who has supported me from the early stage of my research, and who has always challenged me and presented relevant advice. Prof. Keppler and Finon have offered me invaluable discussion time, mentorship and guidance. I would like to express the highest gratitude to my thesis supervisor, Prof. Keppler, who has been committed to my works since the beginning and has always care about my integration into the everyday life at the CEEM[1]. His advices have always been intelligent, extremely useful and has allowed me to accomplish this work with meaningful outcomes. He has entrusted me with carrying my works forward and prized me with freedom and confidence.

I want to thank Timothée Hinchliffe and Vera Silva from EDF. Their expertise and valuable suggestions were very useful for pointing my research in the right direction. I also want to thank Wolf-Peter Schill and Alexander Zerrahn from the DIW. Discussing with you during the development of DIFLEXO has been encouraging and valuable.

I also had the chance to share with particularly supportive colleagues, who has offered me their review and critics during the most important moments. Thanks to Quentin Perrier,

[1] Chair European Electricity Markets, part of the LEDa-CGEMP laboratory of the Paris-Dauphine University.

Marie Petitet and Juan Clavier for their advice all along the way. I am particularly in debt with Charlotte Scouflaire, you have been admirably supportive, discussing with you has proved to be extremely synergetic and your critical eye has, without any doubt, strengthened my research. I have the greatest esteem for the critical scrutiny and your kindness. I would be delighted on extending the collaboration with all of you. I hope to challenge you back on your own research areas.

Victoria V., Fatoumata D., and Julien N. thank you for being so welcoming and kind. Thank you for being so generous to me since my first day in Dauphine. I have spent very pleasant time with you during my stay at Dauphine University. Special thanks to Fatoumata for all her help with administrative requirements, and for all her work behind the scenes.

I am grateful for having been part of the research community of Dauphine and the LEDa. I would like to thank specially Corine Z., Lexane W., Bjorn N., Laurent B., Florence M., José Luis G., Rafael A., Alexandre C. and Hugo L., sharing with you have been very pleasant and inspiring. Thank you for all the fun moments in Dauphine and abroad. Special thanks to Victor C., Simon Q. and Clement B., we have struggled, fight and achieved our goals together, I look forward to continuing sharing with you in research, sport, and life. I want to thank and encourage all the Ph.D. colleagues of the LEDa, particularly Cyril de L., Clara B., Seungman L., Antoine V, Sandra P., Dorianne M., Morgan P., Etienne G., Chris R., Alexis D., Arnlod B., Homero M., Marua R., Sarah M., Leslie B., Zied C., Mohammad I., and Marine T.

I feel immensely fortunate for the truly exceptional individuals that I have met during my stay in Paris, and who have accompanied me during since my arrival. Directly and indirectly, my research has also benefited from the meaningful time spent with friends. In that respect, I have to say that my Ph.D. research and my life in Paris have also benefited from the exchange of interesting ideas and moments with Alexis B. and Antoine de Z. at home and on the roads. Camille V. & Florian, Christopher J., thank you for your kindness and for sharing with me all your knowledge of culture, cinema, and music. It is always great to spare time with all of you.

The BocARiba team has been particularly supportive and comprehensive during the last year of my thesis. Daniel G., Nicolas P., Emilie H., Jorge M. and Lisa B., you are not only my partners, you are my lifetime mates. I have learned very useful lessons from working with every one of you. Daniel, thank you for being always so positive and ambitious, you are a

winner and a great leader. You have taught me from your example how motivation and inspiration work. Nico and Lisa, you are such a talented, creative and passionate individual, but this is just one side of you. As important as your talent is the fact that you are extremely hard-workers, you take care of details, and you always keep things in their proper place. Just by sharing with you anyone can figure out how important these things are for achieving objectives. Jorge and Emilie, you are intelligent, supportive, challenging, but also "kind and tender". You know how to be in the right place at the right time, but not only, you are extremely hard workers, trustful and reliable as well. Special thanks to Pauline, Javier, and Nilou. You all have inspired me during the last months of writing and working on this dissertation.

I want to thank Daniel G., Rodrigo K. and Timothée F. for our brotherhood and the very funny moments shared during my time in Paris. I know that I was not very available during the last months, I'm sure there will be other times. Thanks also to Sebastian B., Tuomas A., Deborah C., Sarah E. and Guillemette de C., for shared amazing experiences and a great time. Thanks to Juliette C., Antoine D., and Irma D. tp Pierre-Alexis C. and Melanie F., Sabine Z., Bertrand B., Pierre C. and Caroline G., Pierre G., Anne G., and Loulou G., Alex B., Lucile D. and Thomas B. Thank you for being so comprehensive and encouraging. You should know that in your company I finally understand the meaning of "la joie de vivre".

I have counted with the unconditional support of my family not only during the development of my Ph.D. research but since the start of my education. You have always motivated my curiosity, challenged me with your exemplarity and integrity. Thank you for showing me the way.

The most valuable source of joy during these years comes from my lifetime companion Camille C. You are a seamless balance of intelligence, power, courage, and beauty. The achievement of this work would not have been possible without all your advice and help. Thank you for being so comprehensive, for supporting me during the hard times and for pushing me to be a better person every day.

Finally, thanks to the Chair European Electricity Markets (CEEM), the CGEMP, to the Paris-Dauphine Foundation and to PSL University for providing me with funds and facilities during the development of my doctoral research. Any opinions, findings, and conclusions presented in this dissertation are those of the authors and do not necessarily represent the view of the CEEM.

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LIST OF ACRONYMS

ACAES:	Adiabatic compressed air energy storage
AMI:	Advanced metering infrastructure
AS:	Ancillary service
BOP:	Balance of plant
BTM	Behind-the-meter
CAES:	Compressed air energy storage
CCGT:	Combined cycle gas turbine
CEM:	Capacity expansion model
CPP:	Critical peak-pricing
CRF:	Capacity recovery factor
CRM:	capacity adequacy mechanism
DCAES:	Diabatic compressed air energy storage
DCC:	Data and communication company
DIFLEXO:	Dispatch, investments and flexibility optimization model
DOE:	American Department of Energy
DR:	Demand-response
DSM:	Demand-side management
DSO:	Distribution system operator
ED:	Economic dispatch
EES:	Electric energy storage
EFOR:	Equivalent Forced Outages Rates
ELCC:	Effective load Carrying Capability
EMS:	Energy management system
EMS:	Energy management system
ENTSO-E:	European Network of Transmission System Operators
EOM:	Energy-only Market
EV:	Electric vehicles
FC:	Fuel cells
FCR:	Frequency Restoration Reserves
FOAK:	First-of-a-kind
FRR:	Frequency restoration reserve

GEM:	Generation expansion model
H_2:	Hydrogen
IRRE:	Insufficient Ramping Resource Expectation
Li-ion:	Lithium-ion batteries
LOLE:	Loss of load expectation
LOLP:	Loss of load probability
LP:	Linear programming
LTGI:	long-term generation investment
MIP:	Mixed integer programming
NaS:	Sodium-sulfur batteries
O&M:	Operation and maintenance
OCOT:	Open cycle oil turbine
OPF:	Optimal power flow
PCS:	Power control system
PHS:	Pumped-hydro storage
PTR:	Peak-time rebates
PV:	Photovoltaic technology
RA:	Resource adequacy
RE:	Renewable energy
RMSE:	Root mean square error
RPS:	Renewable portfolio standard
RR:	Replacement Reserves
RTP:	Real-time pricing
SMES:	Superconducting magnetic energy storage
TOU:	Time of use rates
TSO:	Transmission system operator
UC:	Unit commitment
VPP:	Variable peak pricing
VRB:	Vanadium-Redox batteries
VRE:	Variable renewable energy
VRFB:	Vanadium redox flow batteries
WACC:	Weighted average cost of capital
Zn-Br:	Zinc-Bromine

SYNTHESE GENERALE

INTRODUCTION

La plupart des études récentes sur le système électrique se concentrent principalement sur la nécessité de réduire leur empreinte environnementale et/ou sur l'évaluation de l'impact des nouvelles technologies d'origine renouvelable. Ces deux tendances suggèrent explicitement un changement de paradigme majeur dans le paysage de l'industrie électrique. Parmi les moteurs de ce changement de paradigme figurent les importantes réductions de coûts des technologies renouvelables grâce à leur progrès technique, l'évolution des technologies classiques de production d'électricité, le déploiement massif des technologies de l'information et des télécommunications (IT) permettant une gestion "plus intelligente" de la demande, et les réductions des coûts prometteuses des technologies de stockage.

Par conséquent, la vision commune partagée par toutes les études récentes portant sur les systèmes électriques d'avenir se constitue autour de la transformation du secteur vers des technologies à plus faible émissions de CO_2 et plus "intelligentes". Cette transformation est présentée de manière progressive selon les hypothèses adoptées par rapport aux facteurs qui définissent la compétitivité relative des technologies ainsi que l'ampleur des politiques environnementales considérées. Cette promesse de transformation industrielle est inscrite dans les politiques énergétiques mais a aussi des répercussions sur celles-ci et sur la régulation des marchés en pleine évolution.

Les travaux de recherches développés dans cette thèse tentent d'avoir une contribution double sur les questions précédemment exposées, notamment :

1. **Une contribution méthodologique** : Offrir un cadre de représentation quantitatif des interactions entre les marchés électriques et la variabilité provenant des parts croissantes d'énergies renouvelables. Ainsi, les décisions de court et long terme sont prises en compte simultanément dans l'optimisation du parc électrique. A cette fin, la formulation mathématique proposée est formellement introduite dans le chapitre I, où une description détaillée du modèle développé DIFLEXO est présentée. Certains détails de modélisation sont également brièvement commentés dans les sections méthodologiques des chapitres II et III.

2. **Une contribution aux questions de politique énergétique** : L'objectif est de générer des résultats capables d'enrichir le débat autour des questions sur la transition écologique touchant le secteur électrique, ainsi que ses implications économiques à travers des cas d'études. Ces sujets sont abordés tout particulièrement dans les chapitres II et III, qui présentent et discutent des questions relatives au système électrique français soumis à des objectifs ambitieux de décarbonisation et de transition énergétique aux horizons 2020, 2030 et 2050.

Chaque chapitre présente sa problématique et propose une brève revue de la littérature correspondant à son sujet. Par la diversité des sujets abordés, et pour éviter tout simplification, chaque chapitre présente une discussion complète sur les résultats et met en évidence des conclusions non-générales mais spécifiques.

CHAPITRE I

"A CAPACITY EXPANSION MODEL DEALING WITH BALANCING REQUIREMENTS, SHORT-TERM OPERATIONS AND LONG-RUN DYNAMICS"

L'IMPACT DE LA VARIABILITE DANS LA GESTION DU SYSTEME ELECTRIQUE

Les technologies éoliennes et photovoltaïques, considérées comme des énergies renouvelables variables (ERV), sont devenues aujourd'hui les principales sources d'énergie propre grâce aux développements technologiques et à la baisse des coûts, ainsi qu'aux programmes de soutien financier très avantageux. Mais ces sources sont de nature variable car elles dépendent des facteurs météorologiques. Dû à leur faible coût marginal, ou à d'autres arrangements hors marchés, elles ont la priorité dans la programmation journalière du parc électrique, ce qui laisse au reste du parc une demande résiduelle avec une variabilité accrue. A titre d'exemple, la Figure 1 montre les perturbations introduites dans la demande résiduelle en fonction des différents niveaux de pénétration des ENRv. Néanmoins, les systèmes électriques actuels ont été conçus pour gérer seulement une quantité limitée de variabilité. De même, la gestion des forts niveaux de variabilité pose aussi des difficultés importantes dans les marchés électriques actuels. Les marchés se montrent défaillants (i.e., prix négatifs, forte volatilité de prix, incitations de long terme insuffisantes) et incapables

de coordonner de manière efficace les décisions économiques des acteurs. Donc, si les objectifs de transition énergétique visent un fort déploiement de ces technologies, des nouveaux challenges liés aux besoin de flexibilité devront être adressés.

La flexibilité peut être considérée comme la propriété dynamique du système consistant à la capacité à s'adapter aux conditions changeantes sur des échelles de temps différentes afin de garder des niveaux suffisants de fiabilité. Avec l'essor des ENRv, ces conditions changeantes peuvent provenir soit des chocs de la demande ou de l'offre (i.e., coûts d'intégration des ENRv), et peuvent apparaître soudainement ou être prévisibles ; par conséquent, le temps nécessaire pour le déploiement de la flexibilité est aussi un paramètre crucial à considérer. La fourniture de la flexibilité a également des coûts associés, ce qui signifie que du point de vue économique, ces coûts totaux (ou coûts de système) doivent être pris en compte dans les politiques de transition énergétique.

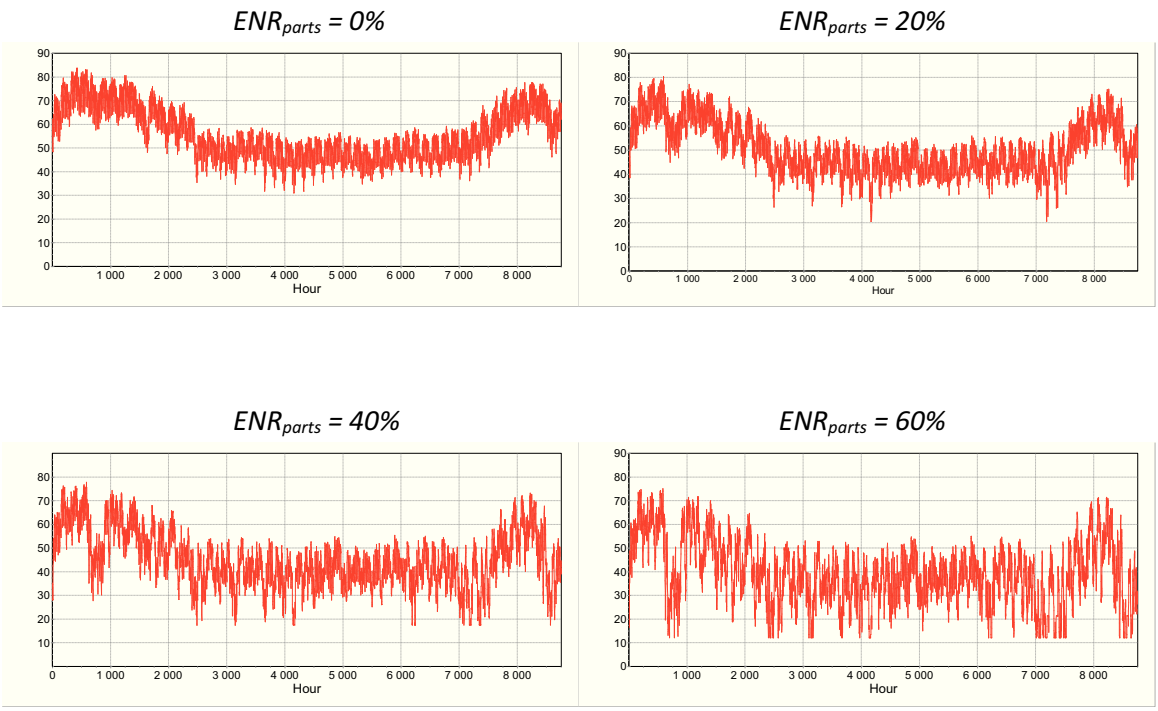

Figure 1. Impact des ENR dans la variabilité de la demande résiduelle

a. La variabilité et ses effets de long terme, court terme et temps réel

Avec des niveaux accrus de variabilité, les besoins du système électrique sont sensés passer d'un problème de dimensionnement de la capacité à un problème d'adéquation complète des ressources, où la fourniture des multiples produits et services sur des horizons temporels interdépendants (Gottstein et al. 2012) devient impérative.

L'inquiétude sur la sécurité d'approvisionnement a suscité un regain d'intérêt avec l'essor des ENRv. Telles qu'exposées dans (Cepeda et al. 2009), la fiabilité et l'adéquation sont deux sujets distincts mais intrinsèquement liés qui se situent au sein de la sécurité d'approvisionnement. L'adéquation de la capacité consiste à disposer des niveaux de puissance supérieurs à la demande de pointe afin de garantir la fourniture à tout moment, compte tenu d'une marge de capacité définie. La faible contribution capacitaire des ENRv, en raison de sa faible prévisibilité au moment d'une éventuelle pointe, nuit à sa valeur système, et crée le besoin d'avoir d'autres moyens de production prêts à être déployés en cas d'absence de production des ENRv.

D'autre part, la fiabilité est définie comme la capacité du système à garantir la fourniture électrique de manière continuelle, donc, surmontant toutes les éventualités soudaines telles que des pannes de centrales, des lignes ou des erreurs de prévision. La pénétration croissante des ENRv a suscité des éléments supplémentaires appartenant à l'équilibrage de court terme en raison de sa variabilité et intermittence. Ce problème est principalement occasionné par la fluctuation de la demande résiduelle (voir Figure 1), ainsi qu'aux erreurs de prévision des apports de l'éolien et du solaire. Donc, les gestionnaires du réseau doivent programmer des niveaux supplémentaires de réserve afin de garantir l'équilibrage de la fréquence.

Non seulement l'intégration système des renouvelables pose des problèmes techniques aux gestionnaires du réseau, mais leur impact sur le marché introduit des externalités négatives sur les modèles économiques des autres technologies (Keppler and Cometto 2012). Le très faible coût marginal de court terme des ENRv, ajouté à sa variabilité, réduit le niveau de prix pour les technologies de base (effet prix). En ce qui concerne les technologies de pointe et d'extrême pointe, la variabilité des ENRv les déplace en dehors du « merit order », ce qui leur fait perdre des revenus nécessaires pour leur survie dans le marché (effet volume), exacerbant ainsi le problème de « missing money » (Joskow 2006), ce qui conduit à la fermeture prématurée des capacités existantes. Tout cela ne fait qu'accélérer des problèmes d'adéquation et d'équilibrage.

En 2013, 21 GW d'usines à gaz ont été mis sous cocon ou fermées en Europe, dont 8,8 GW des centrales avec moins de 10 ans d'exploitation (coûts échoués pour les investisseurs). Le problème est que ces installations sont nécessaires pour garantir l'adéquation de la capacité, mais aussi pour fournir la flexibilité supplémentaire essentielle pour couvrir les fluctuations des ENRv.

b. La flexibilité comme service transversal aux systèmes électriques avec forte pénétration des ENRv

En ce qui concerne le besoin de capacité, Castro et al. (2008) expliquent que le crédit de capacité de l 'éolien dépend des caractéristiques de la ressource ainsi que de la zone géographique considérée, mais aussi des caractéristiques du parc existant. Leur travail consiste à analyser le crédit de capacité éolienne à l'aide d'une mesure métrique[2] pour mesurer sa contribution en référence à une technologie conventionnelle équivalente. Ils comparent cette métrique sur un système avec et sans station de turbinage et pompage (STEP). Une méthodologie probabiliste est développée pour contraindre le système à des niveaux de fiabilité équivalents en utilisant l'espérance de perte de charge (LOLE[3]). Enfin, les auteurs montrent comment la valeur capacitaire éolienne est accrue par l'existence de sources de production flexibles sur le mix énergétique comme le STEP, qui permet une amélioration de la flexibilité du système. Des résultats similaires ont été exposés dans (Sullivan, Short, and Blair 2008), qui examinent l'impact du stockage pour l'intégration des ENRv à l'aide d'un modèle d'investissement. Ils soulignent que la présence du stockage conduit à une meilleure intégration des ENRv.

Telles qu'indiquées dans (B. S. Palmintier and Webster 2013), les fluctuations de la demande résiduelle avec une forte pénétration des ENRv exigent une représentation plus détaillée des contraintes opérationnelles dans les études de planification du parc électrique. L'omission de certaines d'entre elles peut conduire à des « biais dans les coûts et/ou le rendement réel d'opération, donc, à une planification sous-optimale du parc ou même irréalisable ». Poudineh (2016) indique que pour des niveaux élevés de pénétrations d'ENRv, les ressources disponibles peuvent ne pas être suffisantes pour gérer les variations de la demande résiduelle. Il affirme que « les métriques de fiabilité traditionnelles comme le LOLE doivent

[2] Cette métrique est le "Effective Load Carrying Capability" (ELCC)
[3] LOLE est l'acronyme en anglais du " Lost of Load Expectation"

être complétées par d'autres mesures » pour tenir compte que la capacité du système à suivre des rampes extrêmes, afin de garantir une capacité disponible qui suive les fluctuations de court terme, avec suffisamment de flexibilité.

De plus, des nouvelles études évaluent les besoins supplémentaires de réserves dues aux ENRv (Hirth and Ziegenhagen 2015; De Vos et al. 2013) et exposent les avantages d'une évolution vers un dimensionnement dynamique des réserves lorsque l'incertitude du système est exacerbée. Ces méthodologies sont basées dans l'étude statistique des déséquilibres du système. De même, l'ENTSO-E a proposé des principes directeurs novateurs pour le dimensionnement des réserves de soutien à la fréquence (FRR) dans (ENTSO-E 2013). Il suggère de prendre en compte l'incertitude de la génération des ENRv pour programmer des niveaux de FRR nécessaires pour couvrir les erreurs de prévision et les potentiels déséquilibres résiduels. Les besoins de réserves sont donc revus à la hausse en cas de fort apport des ENRv, ce qui pourrait aussi être interprété comme des besoins de flexibilité accrue pour garantir l'ajustement.

C'est ainsi que la valeur de la flexibilité en tant que capacité à moduler à volonté les apports et/ou soutirages de manière rapide et en suivant l'état du système, devient une propriété clef dans l'intégration des énergies renouvelables dans le long, moyen et court terme.

c. *La planification du secteur face aux besoins de flexibilité : vers des nouveaux modèles de d'optimisation du parc électrique*

A travers le constat ci-dessus, des nouvelles méthodologies de planification du parc électrique ont commencé à y répondre. Le défi des nouveaux modèles de planification est de combler le fossé entre les modèles d'exploitation et les modèles d'investissement. Ils utilisent des outils avec une granularité très fine et avec des formulations très détaillées pour représenter les contraintes opérationnelles du système, mais suffisamment abrégées pour ne pas compromettre sa résolution et respecter des temps de calcul raisonnables (Carrión and Arroyo 2006; Frangioni, Gentile, and Lacalandra 2009; Hedman et al. 2009; Ostrowski, Anjos, and Vannelli 2012; Rajan, Takriti, and Heights 2005; Ramos et al. 2013; Xian HE , Erik Delarue , William D ' haeseleer 2006).

Actuellement, l'exploitation du parc électrique est optimisée avec des méthodes spécifiques à chaque horizon temporaire. Aussi, les méthodes de dispatch économique (ED) sont

utilisées pour obtenir la programmation journalière du parc, et celles d' « unit commitment » (UC) et « d'optimal power-flow » (OPF) pour la programmation infra-horaire. Toutefois, les efforts de recherche actuels visent à combiner ces méthodes avec l'optimisation des investissements afin d'intégrer les besoins de court terme dans la planification de long terme (Campion et al. 2013; B. Palmintier and Webster 2014; Poncelet et al. 2014; Viana and Pedroso 2013). Ceci permettrait de faire évoluer les modèles actuels de planification du parc, qui sont basés sur des algorithmes à boucle fermée (capacité, opération et ajustement), par des approches de co-optimisation où les besoins appartenant aux trois horizons temporaires (capacité, opérabilité et fiabilité) sont considérés de manière simultanée.

PRESENTATION DU MODELE D'OPTIMISATION DIFLEXO

Le rôle des nouvelles sources de flexibilité (e.g., stockage, DSM) pour l'intégration des renouvelables, mais aussi celui des technologies classiques de génération, peuvent fournir de multiples services dont la flexibilité du système. Celle-ci devrait être étudiée dans un cadre élargi de planification des investissements où les caractéristiques techniques et les coûts associés à chacune d'entre elles soient contemplés sur des bases d'égalité. Ceci implique le développement d'un outil de planification de la capacité inscrit dans les considérations précédentes (multiservices et co-optimisation de ressources). De cette manière, des effets de complémentarité et d'éviction entre les nouvelles technologies peuvent être considérés, tout particulièrement entre les services fournis par le stockage et le pilotage intelligent de la demande.

Sur ces principes, le modèle DIFLEXO a été développé lors de cette thèse. Il est un outil d'optimisation mathématique pour la planification des investissements tenant compte des multiples besoins du système et des contraintes techniques des technologies. Il est fondé sur les travaux de Palmintier (2014); Poncelet, Van Stiphout, et al. (2014) et Zerrahn and Schill (2015), et développe tout particulièrement la représentation des technologies du stockage. Sa construction modulable permet de tester facilement les compromis existants entre dimensionnalité, complexité et précision, à différents niveaux de pénétration des ENRv[4].

[4] L'exposition complète du modèle avec des illustrations peut être consulté sur : http://www.ceem-dauphine.org/assets/wp/pdf/CEEM_Working_Paper_25_Manuel_VILLAVICENCIO1.pdf

CAS D'ETUDE I : LES EFFETS DE LA REPRESENTATION DES BESOINS SYSTEMES SUR LE DEVELOPPEMENT OPTIMAL DU PARC ELECTRIQUE

DIFLEXO a été testé en utilisant trois formulations avec l'introduction progressive du détail dans les contraintes opérationnelles lors de la planification des capacités. Chacune des formulations simule les investissements optimaux à des parts croissantes des ENRv.

La première formulation testée, dénommée F1, est la formulation complète comprenant des besoins de réserve (FRR), des contraintes opérationnelles dans l'équilibre horaire et des pertes d'efficacité à charge partielle. La deuxième formulation, dénommée F2, comprend toutes les considérations précédentes mais ne tient pas compte des besoins de réserve. La troisième formulation étudiée, F3, ne prend en compte que l'équilibre horaire et l'adéquation de la capacité. Les paramètres techniques et les hypothèses de coûts demeurent les mêmes pour les trois formulations.

Les Figure 2 et Figure 3 montrent les effets de l'introduction des ENRv sur les investissements pour chaque formulation, et permettent de comparer leur influence dans le développement optimal du parc.

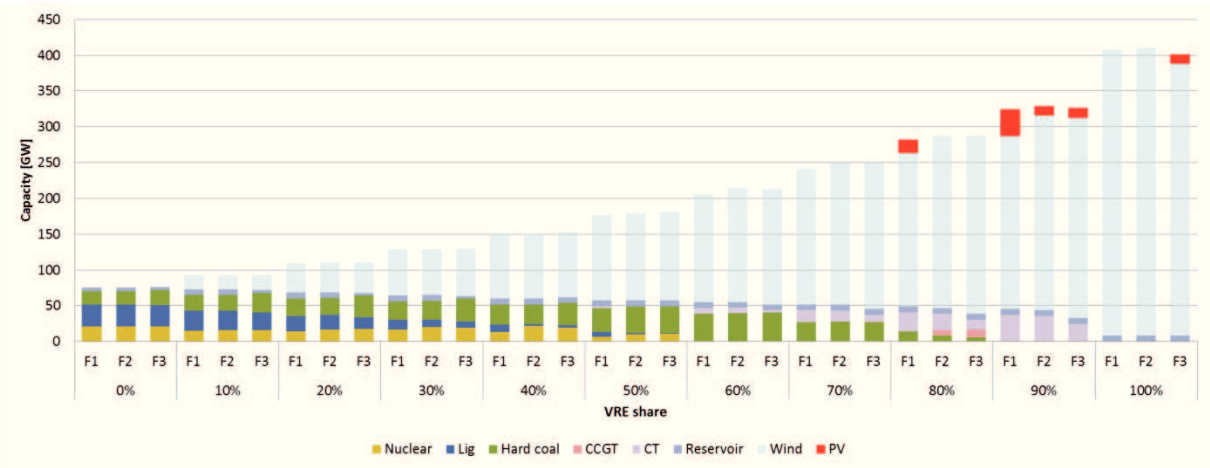

Figure 2. Investissements optimaux de capacité dans un scénario « greenfield »

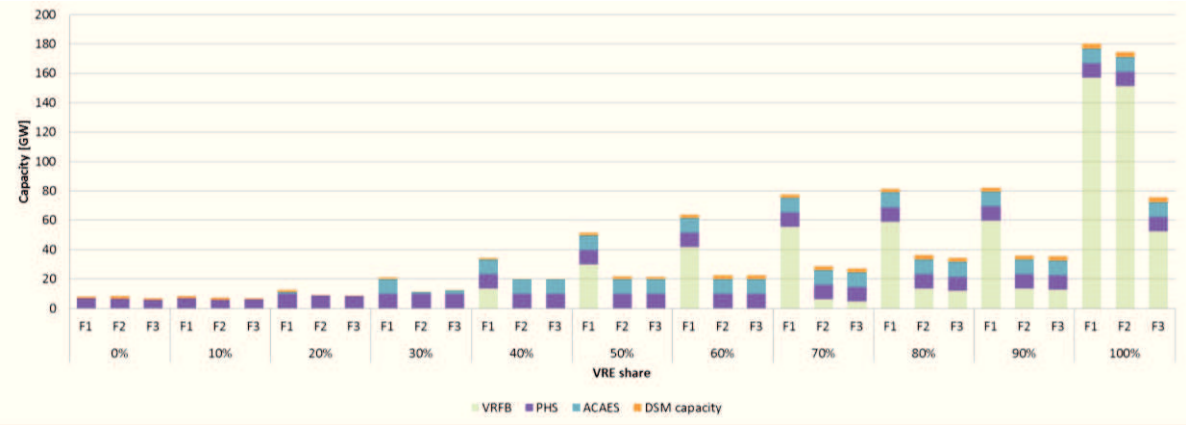

Figure 3. Investissements optimaux de flexibilité optimale dans un scénario « greenfield »

Les résultats montrent qu'à faible pénétration des ENRv (entre 0 et 20 %) les trois formulations conduisent à des résultats très similaires : les capacités optimales sont très proches en niveau et type ; il en va de même pour le coût du système et les émissions de CO_2 qui en résultent. Les besoins de flexibilité sont faibles ; seule la flexibilité pour l'adéquation de la capacité et le dispatch optimal du parc est valorisée. Par conséquent, à ces niveaux de variabilité, les unités de production conventionnelles fournissent suffisamment d'énergie et de flexibilité au système.

Ce n'est qu'à partir de 30% de pénétration des ENRv qu'une plus grande flexibilité est valorisable, car l'intégration des ENRv devient contraignante. Ce constat n'apparaît que dans la formulation la plus complète (F1), tandis que les formulations simplifiées (F2 et F3) ne montrent des investissements équivalents dans les technologies de flexibilité qu'à des niveaux de pénétration entre 70 et 80%. Ceci confirme qu'une représentation abrégée des contraintes opérationnelles peut conduire à des investissements sous-optimaux, voire à un mix électrique incapable de fournir tous les services nécessaires. Les investissements sur les options de flexibilité apparaissent plus tôt et augmentent plus rapidement lorsqu'une représentation plus complète des caractéristiques dynamiques du système est adoptée.

CONCLUSIONS DU CHAPITRE I

La planification du système électrique avec une forte pénétration des ENRv pose des défis de modélisation essentiels. Ces travaux tentent ainsi d'apporter des éléments de réponse à ces problèmes. Le modèle DIFLEXO y est développé et illustré au travers de formulations

mettant en lumière l'impact de la représentation des contraintes opérationnelles tout en optimisant de manière endogène les investissements de capacité et de flexibilité.

La contribution de ce chapitre est double. Premièrement, les investissements endogènes dans les options de flexibilité sont incorporés dans un modèle de planification de la capacité. Dans cette configuration les capacités de stockage et pilotage intelligent de la demande sont co-optimisées avec des investissements classiques de capacité et d'ENRv. Deuxièmement, la représentation conventionnelle des modèles de planification du parc, basées uniquement sur l'adéquation de la capacité, est élargie par l'introduction des besoins de flexibilité et fiabilité, qu'imposent des besoins supplémentaires pour l'ajustement de court terme (FRR).

En résumé, la notion de flexibilité a été analysée et interprétée comme un service transversal en fonction de multiples délais d'activation, servant à des fins différentes et pouvant être fournie par différentes technologies. Une comparaison des formulations à différent niveau de détails dans les contraintes opérationnelles du système a été proposée. Les résultats confirment les postulats évoqués dans la littérature sur les liens existants entre variabilité, besoins de flexibilité et valorisation des technologies de stockage et DSM. Aussi, à l'horizon 2020, les sources de flexibilité auront un rôle majeur à jouer lorsqu'il s'agira d'intégrer des parts de plus en plus importantes en ENRv.

CHAPITRE II

"THE VALUE OF ELECTRIC ENERGY STORAGE AND ITS WELFARE EFFECTS: THE CASE OF FRANCE"

L'évaluation de la valeur des nouvelles ressources de flexibilité est une question étroitement liée à la méthodologie et à la représentation du système adopté. La valeur des technologies de flexibilité, doit être appréhendée du point de vue multiservice. Elle doit tout d'abord tenir compte des interactions entre les technologies de production et les autres sources de flexibilité pouvant créer des effets d'éviction et de complémentarité. Ces derniers impliquent de s'intéresser simultanément aux coûts directs (investissement, frais d'exploitation, coût de combustible) et aux coûts de système (intégration au réseau, ré-équilibrage du système, etc.), réputés significatifs pour les ENRv à partir d'un certain seuil de déploiement.

De plus, le choix technologique composant les systèmes électriques du futur ne doit pas être seulement basé sur le coût de revient d'une unité d'énergie, mais sur la valeur des différentes

technologies pour garantir la fourniture du service électrique. Joskow (2011) souligne les défauts de l'utilisation de mesures basées sur les coûts de revient simplifiés, du type LCOE, pour comparer la valeur complète des technologies de différente nature, et insiste sur la nécessité d'adopter des approches systémiques, plutôt que de comparer des simples mesures fondées sur les coûts

Une distinction doit être faite entre les technologies de production d'électricité dispatchables et celles intermittentes. Dans (Keppler and Cometto 2012), les auteurs explorent la question en soutenant que les ENRv génèrent des externalités qui sont traduites en coûts supplémentaires "au-delà des limites des générateurs". Ils adoptent donc une perspective systémique pour élargir la comparaison de la valeur des ENRv par rapport aux technologies susceptibles d'être pilotées, en accordant une attention particulière à l'énergie nucléaire. Dans ce cadre, ils expliquent la nature principale des externalités des ENRv en utilisant les deux catégories introduites par Scitovsky (1954). D'une part, les ENRv induisent des externalités techniques lors de l'introduction de la variabilité dans l'offre. Ces externalités sont des relations asymétriques entre les acteurs du marché "dans lesquelles les parties affectées n'ont aucun moyen de répondre" à ceux qui les produisent. D'autre part, les ENRv induisent des externalités pécuniaires du fait de leurs très faibles coûts marginaux de court terme. Ces externalités "opèrent par le mécanisme des prix" et doivent être absorbées par le design du marché.

En vue de développer davantage leurs conclusions, Joskow et, Keppler et Cometto soulignent la nécessité de combler l'écart entre les approches basées sur les coûts et les approches systémiques. Il s'agit pour les premières de traiter les aspects économiques des technologies au niveau des centrales, sans tenir compte du reste du système électrique (i.e., valeur privée). Les deuxièmes donnent quant à elles, une meilleure représentation des caractéristiques opérationnelles des centrales et de leurs interactions dans des systèmes proches de l'équilibre économique sans tenir compte de la rentabilité individuelle des projets (i.e., valeur système). La juste estimation de la valeur des nouvelles technologies de flexibilité doit donc être inscrite dans l'opposition valeur privée – valeur publique.

Dans ce contexte, l'électricité doit être conçue aussi bien comme un vecteur énergétique qu'un bien d'échange. Ceci est une condition préalable pour lui assigner l'attribut principal de tout bien économique réel : l'hétérogénéité. D'un point de vue économique,

"l'hétérogénéité de l'énergie électrique" justifie les variations de sa valeur marginale liées à sa localisation dans le réseau, à sa temporalité et à sa fiabilité de fourniture.

Chacun de ces facteurs doit être conçu comme un élément du problème à équilibrer. Dans (Hirth, Ueckerdt, and Edenhofer 2016), cette question est exposée d'une manière particulièrement intuitive : physiquement, "les technologies produisent la même produit (MWh d'électricité)", mais économiquement, "elles produisent des biens différents", servant à des fins diverses. L'idée clé reflétée par Hirth et ses co-auteurs réside dans la « substituabilité » des biens : un mégawattheure d'électricité n'est qu'imparfaitement substituable au long des différents temps de livraison, points réseau et états du système.

Par conséquent, chaque centrale de génération, y compris le stockage et la DSM, devrait être appréhendée comme un producteur équilibrant les différentes dimensions d'un actif hétérogène, avec ses propres limites techniques. Ainsi, chaque dimension à équilibrer correspond à un service à substituabilité limitée. De cette façon, l'ensemble des interactions entre les besoins du système, les actifs d'approvisionnement et leurs coûts connexes peuvent être correctement analysés.

LE ROLE DU STOCKAGE ET LA QUANTIFICATION DE SA VALEUR ECONOMIQUE

Le stockage peut jouer un rôle crucial dans la fourniture des multiples services appartenant au système électrique. Il peut générer de la valeur en permettant le report des investissements, permettre des économies de carburant, des coûts d'usure, mais aussi améliorer la stabilité et la sécurité du système. Il facilite également l'intégration des ENRv et protège les usagers contre des aléas des prix du carburant. De plus, le développement de cette filiale peut entraîner des avantages qui se répandent hors du secteur électrique lui-même, comme le développement industriel, la création d'emplois, l'amélioration de l'indépendance énergétique, etc. Par conséquent, une définition comptable ainsi qu'une délimitation claire des frontières doivent être définis lors de toute tentative de quantification de la valeur du stockage.

La valeur du stockage est définie dans cette étude comme les gains nets et monnayables au niveau du système, générés directement ou indirectement par le stockage à condition que les allocations en capacité, le dispatch économique des centrales et les décisions d'inventaires soient simultanément optimisés. En ce sens, la valeur du stockage se réfère à

une condition d'équilibre du marché obtenue par le déploiement conjoint des capacités classiques de production et du DSM, en ne considérant que le système électrique. La valeur marchande du stockage, dénommée la valeur privée, est le bénéfice net obtenu en soustrayant les recettes cumulées provenant de la participation au marché et ses coûts associés.

Suivant la méthodologie de (Strbac et al. 2012), la valeur système du stockage est comptabilisée par les économies nettes qu'il induit. Celles-ci sont calculées sous la forme d'une différence entre les coûts totaux considérant l'ensemble complet des technologies, et ceux contrefactuels où les technologies de stockage sont arbitrairement exclues. Dans cette configuration, le déploiement économique du stockage n'a de sens que si les premiers sont bien inférieurs aux deuxièmes. Le modèle d'investissement DIFLEXO est donc utilisé pour optimiser le parc électrique dans ces deux configurations en optimisant les décisions d'expansion et de fermeture des capacités existantes dans le parc français en 2015.

CAS D'ETUDE II : La valeur du stockage en France dans les objectifs de la loi sur la transition énergétique

En France, la loi pour la transition énergétique (loi n° 2015-992) définit l'objectif de contribution des énergies renouvelables aux horizons 2020 et 2030, à respectivement 27 et 40 %. En outre, la capacité nucléaire devrait être plafonnée à 63,2 GW et sa contribution devrait passer de 75 à 50 % d'ici 2025[5]. Ainsi, une valeur du stockage électrique pourrait être quantifiable.

Les résultats des simulations montrent qu'à l'horizon 2020, le déploiement économique du stockage n'a pas lieu. Le parc existant est complètement capable d'intégrer l'objectif des 27% d'ENRv, mais, ce n'est qu'en 2030, avec une plus forte pénétration des ENRv, une part plus faible du nucléaire, et grâce à une diminution plus accentuée des coûts du stockage, que celui-ci devient optimal et diminue le coûts système.

La Figure 4 montre les différentes catégories du coût système affectées par la présence du stockage. Certaines d'entre elles subissent des surcoûts, dénotées par des coûts négatifs (i.e., les colonnes en rouge correspondant aux coûts opérationnels et aux coûts des émissions

[5] Les objectifs concernant la sortie du nucléaire ont été reportés en novembre 2017 par le Ministère de la Transition Ecologique, qui cible maintenant la période 2030-2035.

totaux), tandis que la variation d'autres est positive (e.g., coûts de « ramping », de combustible mais aussi des coûts échoués et des coûts d'investissements), dénotant des économies. Le déploiement optimal du stockage permettrait de dégager une valeur économique d'environ 352 millions par an en 2030, ce qui correspond à environ 1,3% du coût total annualisé du système.

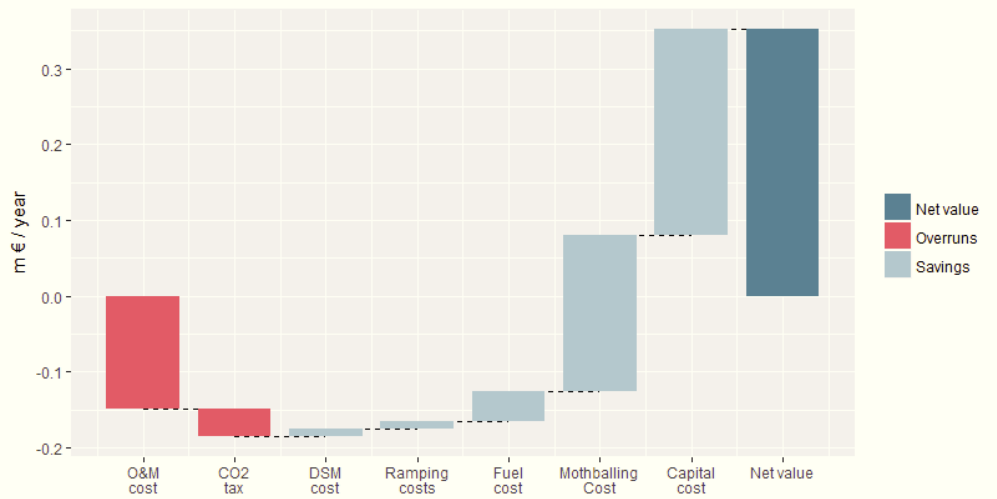

Figure 4 .Valeur système des investissements optimaux en technologies de stockage en 2030

Mais ce développement vient également occasionner des effets de redistribution entre les acteurs du marché dû à ses effets sur les prix et sur les volumes. La Figure 5 montre les effets de redistribution nets par type de technologie sous un développement optimal du stockage en 2030. On constate alors que les consommateurs inflexibles, les unités d'ENRv et le stockage sont gagnants en termes d'excédent net, alors que le reste des technologies voit leur excèdent diminuer. Ce sont les technologies conventionnelles (i.e. thermique charbon, CCGT-gaz, nucléaire) qui subissent les pertes les plus importantes due à la réduction du prix moyen sur le marché de l'énergie et du prix de capacité.

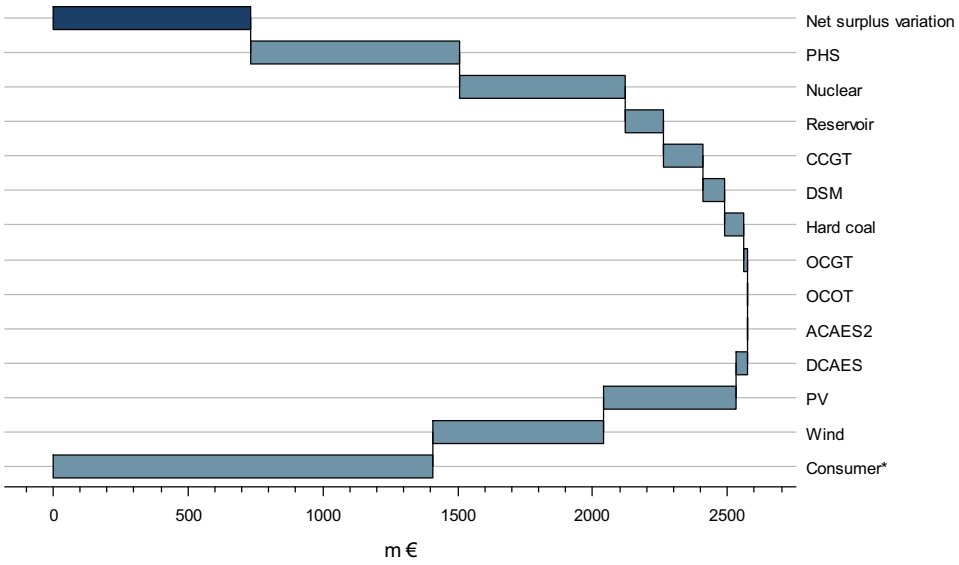

Figure 5. Effets redistributifs du stockage en 2030

CONCLUSIONS DU CHAPITRE II

Lorsque des capacités très significatives d'ENRv sont imposées dans le système, les investissements dans différentes techniques de stockage, de même que les investissements en effacement, permettent d'améliorer la valeur économique des capacités ENRv ainsi que de dégager la valeur économique du système dans son ensemble.

En supposant que les marchés du produit d'énergie et des services divers soient équilibrés par l'alignement des prix sur leurs coûts marginaux respectifs,

L'entrée du stockage dans les différents marchés entraîne des évolutions des prix et des quantités vendues par chaque unité de production, créant inévitablement des gagnants et des perdants parmi les acteurs du marché. D'une part, on constate que les producteurs d'ENRv réalisent d'importants bénéfices grâce à un stockage optimal en améliorant leur intégration au marché. D'autre part, même si les revenus sur le marché de l'énergie restent stables pour les centrales de base, leurs bénéfices diminuent en raison de la baisse des revenus provenant des marchés de capacité et des services-système.

Par ailleurs, le stockage améliorerait l'utilisation des technologies de base indépendamment de son empreinte carbone. En conséquence, des incitations (ou des réglementations) environnementales complémentaires seraient nécessaires pour que le stockage contribue aux objectifs de réduction des émissions.

CHAPITRE III

"PROPER PLANNING AND POLICIES PREVENT POOR PERFORMANCE ON POWER SYSTEMS TOO:

ON THE LONG-TERM GOVERNANCE OF THE FRENCH ENERGY TRANSITION"

Depuis les premières études ciblant le développement optimal du système électrique (Bessiere 1970; Grubb 1991), à travers des études plus actuelles utilisant des méthodologies plus complètes (Bouffard and Galiana 2008; Green and Vasilakos 2011), jusqu'aux développements récents combinant des outils de simulation de pointe avec des données très détaillées (Brouwer et al. 2016; Després et al. 2017; Eriksen et al. 2017; Lorenz 2017), la planification du système électrique a été un domaine de recherche dynamique avec des résultats atteignant une précision redoutable.

Toutefois, il s'agit toujours d'un domaine en continuelle évolution, alimenté par le contexte de politique énergétique en vogue. L'avènement de la libéralisation et l'intégration des marchés électriques européens a transformé l'intérêt pour la planification de long terme vers l'analyse des politiques énergétiques et des cadres réglementaires adéquats pour la régulation du marché. Mais le marché ne parvient pas à traiter entièrement les externalités environnementales et les questions de fiabilité du système (IEA 2006).

La part croissante des énergies renouvelables variables (ENRv) produit des distorsions dans le fonctionnement du marché ainsi que d'autres défis pour leur intégration aux systèmes. De nouvelles questions concernant l'adéquation de la capacité, de fiabilité et de flexibilité apparaissent (Druce et al. 2015). L'impact environnemental lié aux émissions de CO_2 générés devient un facteur clé de politique énergétique. Ainsi, une analyse approfondie des interactions entre l'intégration des ENRv, la flexibilité, les émissions de CO_2 générés et les coûts système résultants, semble cruciale dans la conception des politiques efficaces pour la gouvernance de la transition énergétique.

La plupart des études actuelles servant de support aux décideurs en matière de politique énergétique adopte un cadre prospectif, ou propose des feuilles de route ciblant le développement des différentes technologies sous de multiples scénarii prédéfinis. Ces études sont pertinentes pour analyser la faisabilité technique et l'impact économique des politiques énergétiques, mais ne constituent pas en soi des outils pour l'élaboration ex-ante

de celles-ci. Les objectifs ciblés par de telles politiques constituent les hypothèses centrales utilisées dans ces études. Aussi, ils ne peuvent pas être mis en question ou comparés avec d'autres options possibles. D'un point de vue économique, ce problème devrait être reformulé de manière à répondre à la question suivante : Quelle serait la meilleure combinaison des technologies, compte tenu des progrès technologiques actuels et prévus à un horizon donné, qui permettrait d'opérer le système de manière fiable, avec de faibles niveaux d'émission de CO_2 et au moindre coût ? Il convient de noter que cette question n'exclut pas la possibilité d'obtenir comme résultat un portfolio d'investissements d'une ou de plusieurs technologies (e.g., 100% renouvelables), mais elle permet de recentrer le cadre du design des politiques énergétiques avec l'efficacité économique. Ce chapitre essaie donc de répondre aux questions suivantes : combien coûterait-il d'atteindre des objectifs de décarbonisation du parc et/ou des objectifs de pénétration des ENRv ? Quel coût supplémentaire serait nécessaire afin de respecter les objectifs de telles politiques en comparaison aux résultats produits par une stratégie « laissez-faire », qui ne tiendrait compte que de l'évolution de la rentabilité des différentes technologies ?

CAS D'ETUDE III : Evaluation quantitative des politiques énergétiques pour atteindre les objectifs Français de transition écologique à l'horizon 2050

Afin de mieux représenter les capacités rendues possibles par les technologies du réseau intelligent, le modèle DIFLEXO a été élargi avec des modules plus détaillés de gestion intelligente de la demande (GID). Ces programmes comprennent la tarification dynamique, ainsi que d'autres régimes tarifaires incitatifs (e.g. heure point/heure creuse, contrats d'effacement purs, entre autres) pour valoriser la flexibilité du côté du consommateur. La convention proposée par Alstone et co-auteurs (2017) a été adoptée pour mieux représenter la GID dans DIFLEXO. Ces auteurs synthétisent les différents programmes de GID en quatre catégories de « demand-response » (DR) bien définies, à savoir, « Shape », « Shift », « Shed » et « Shimmy ». Cette méthode est jugée utile pour représenter efficacement ces services au sein des blocs d'équilibrage du modèle et, en même temps, facilite l'interprétation des résultats. Le potentiel de GID est calibré par rapport aux études de l' ADEME (2015) et RTE (2017). Il tient compte des flexibilités appartenant à l'électrification du secteur du transport, aux usages électriques pour produire de l'eau chaude sanitaire dans le secteur résidentiel, au potentiel du chauffage et climatisation dans le secteur résidentiel, aux appareils électroménagers et aux processus industriels de longue et courte durée.

Du côté de l'offre, les hypothèses sur les technologies de production et de stockage envisagées d'ici 2050 sont fondées sur les perspectives technologiques présentées par la JRC (2014), prenant en compte le progrès technique et l'évolution des coûts. Hormis les ENRv évoluées capables de fournir des services système et les technologies classiques de génération aussi évoluées, l'ensemble des technologies de stockage comprend le stockage par pompage et turbinage (PHS), les batteries Li-ion (Li-ion), l'hydrogène avec piles à combustible (H2-FC) et trois types de stockage d'énergie à air comprimé (CAES), tels que les CAES souterrains (undCAES), les CAES aériens (aboCAES) et les CAES adiabatiques (AA-CAES).

En 2050, l'objectif officiel publié dans le cadre de la Stratégie Nationale Bas Carbone (SNBC) sortie en novembre 2015 est de parvenir à une réduction de 96% des émissions de CO2 du secteur électrique par rapport aux niveaux de 1990[6]. Parallèlement, l'administration française plaide en faveur d'une transition énergétique profonde vers les énergies renouvelables. Ces orientations posent des questions de politique énergétique capitales sur la faisabilité d'une transformation du système électrique français pilotée par le marché, sur le besoin de politiques énergétiques additionnelles pour inciter d'autres investissements, et sur des coûts associés à ses interventions réglementaires.

Dans ce cadre, les politiques énergétiques peuvent être évaluées de manière précise et appropriées. Dans le contexte actuel de dérégulation du marché électrique, le rôle du planificateur consiste à choisir et calibrer de manière appropriée le meilleur ensemble de politiques capables de donner les meilleures incitations aux acteurs afin d'atteindre des objectifs sensés. Ainsi, deux politiques de haut niveau sont testés : a) Une politique limitant les émissions de CO2 du parc électrique, b) Un mandat ciblant les parts des renouvelables (RPS) dans la consommation totale. L'évaluation des interventions réglementaires ainsi mise en place permet d'accentuer leur impact plutôt que de discuter de leur mise en œuvre.

La Figure 6 synthétise les effets de cette évaluation :

[6] Le communiqué officiel souligne que les objectifs sectoriels ciblant le système électrique sont encore indicatifs, mais il donne une vision claire de la magnitude des objectifs annoncés vers 2050. De plus amples détails sont disponibles dans la publication du ministère :

https://unfccc.int/files/mfc2013/application/pdf/fr_snbc_strategy.pdf

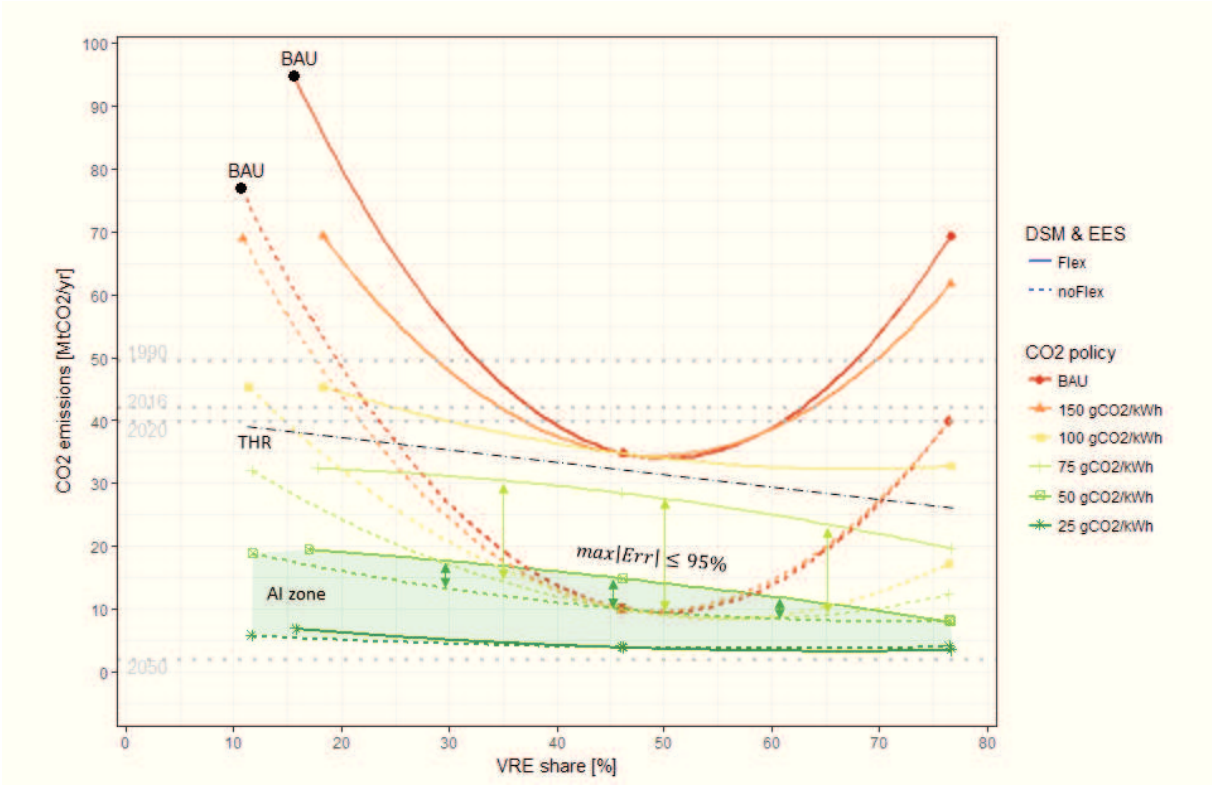

Figure 6. Effet des politiques énergétiques sur le niveau d'émissions de CO2

1. Une politique carbone constitue un instrument efficace pour réduire les émissions de CO2. Afin d'atteindre les objectifs fixés pour 2050 celle-ci devrait être suffisamment contraignante (i.e. ciblant au moins 50 gCO2/KWh). Elle permettrait ainsi d'augmenter la part des renouvelables, sans aucun type de subvention additionnelle, jusqu'au seuil de 18%, à condition d'un cadre règlementaire favorable pour le développement du stockage et de la GID.
2. Un mandat fixant la part des ENR dans le mix électrique conduirait, à lui seul, à une réduction des émissions mais ce jusqu'à un certain seuil (i.e. la concavité positive de la courbe rouge dans la Figure 6) à partir duquel les besoins de flexibilité deviendraient de plus en plus importants. Dans l'absence de politique carbone, ou à des niveaux insuffisamment contraignants sur le CO2, la fourniture de cette flexibilité serait polluante, donc, à partir de 50% de pénétration, une augmentation des parts des ENRv impliquerait une augmentation des émissions.
3. Le développement optimal des nouvelles options de flexibilité, comme le stockage et la GID, seraient nécessaires afin de mieux intégrer les ENRv dans le système, mais seraient insuffisantes pour réduire efficacement le niveau d'émissions du parc électrique. Au contraire, elles pourraient occasionner une augmentation des émissions due aux externalités

environnementales des arbitrages économiques suivant les prix du marché. Ceci peut être représenté par la domination des courbes rouges, oranges et jaunes à trace solide par rapport aux lignes pointillées dans la Figure 6. La seule manière de rendre ces arbitrages plus vertueux serait à travers d'une politique carbone plus contraignante. Ceci permettrait d'intégrer le coût des externalités au signal prix du marché, et conduirait à des niveaux d'émissions décroissants à tout niveau de pénétration des ENRv (e.g., cet effet est aperçu par les courbes convergentes en couleur verte dans la Figure 6).

Les compromis économiques concernant l'ampleur des objectifs de transition écologique du secteur électrique peuvent être appréciés au travers d'une représentation avec des courbes d'efficacité de Pareto comme le montre la Figure 7. On peut affirmer que le déploiement économique des nouvelles options de flexibilité permettrait de réduire les coûts système à n'importe quel niveau de pénétration des ENRv. Le coût supplémentaire de la mise en œuvre des deux politiques analysées varie entre 3 et 25 % selon le niveau de ENRv ciblé, quand la flexibilité est développée de manière optimale.

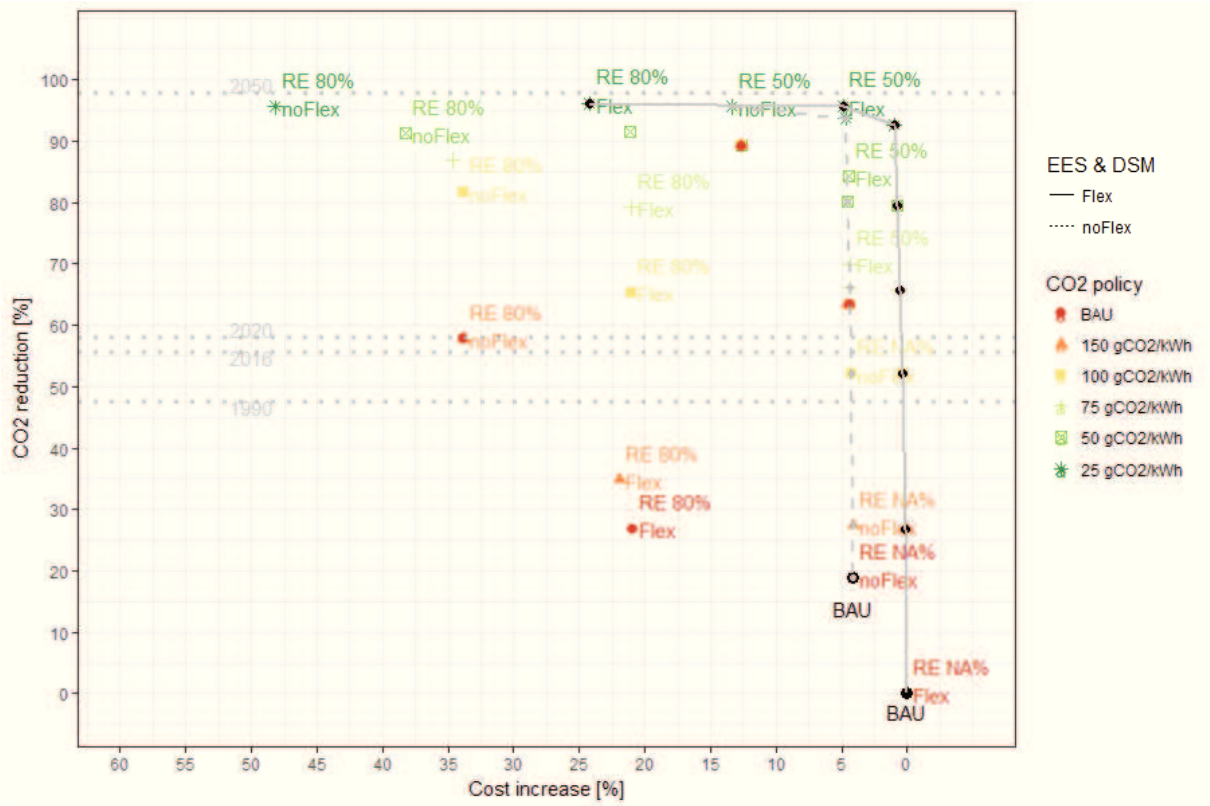

Figure 7. Courbes d'efficacité de Pareto des politiques énergétiques

DISCUSSION ET CONCLUSIONS DU CHAPITRE III

Ce chapitre propose à la fois une méthodologie cohérente pour l'évaluation des politiques de transition énergétique, et un cadre analytique complet basée sur les courbes d'efficacité de Pareto. Ce dernier permet de saisir l'ampleur et les coûts de ces politiques.

Un cas d'étude basée sur le système électrique français est présenté. La loi sur la transition énergétique (2015) vise une réduction des émissions de CO2 du secteur électrique de l'ordre de 96 %, par rapport aux niveaux de 1990, ainsi que jusqu'à 80 % des parts d'énergies renouvelables à l'horizon 2050.

Les résultats de l'analyse montrent que malgré des prometteurs progrès techniques, d'une réduction des coûts très favorable au déploiement des énergies renouvelables, du stockage et des technologies des réseaux intelligents, l'évolution du parc électrique dans une stratégie « laissez-faire » ne peut atteindre qu'entre 12 et 18 % des parts d'ERV à l'équilibre et sans subventions (i.e., part optimale des ENRv). Dans l'absence d'un signal prix de CO2, Ceci conduit à des niveaux d'émissions similaires à celles des années 1990. Ainsi, afin de respecter les objectifs déclarés pour 2050, une politique très rigoureuse en matière de CO2 serait nécessaire. Celle-ci devrait être calibrée sur des émissions spécifiques d'au moins 50 g/KWh via un mécanisme de marché du type « contract-for-difference », ou un mécanisme de « carbon floor » au niveau national qui complémenterait le prix de la tonne de l'EU-ETS. Parallèlement, des mécanismes de soutien aux ENRv seraient aussi nécessaires pour atteindre des objectifs aussi ambitieux concernant l'apport des renouvelables.

GENERAL INTRODUCTION

Long-term power system planning is a challenging task, which outcome is related to system specific characteristics such as the natural resource endowments, the technology prospects, the fuel cost expectations, and the levels and patterns of future demand. These multitude of issues render outcomes hardly comparable between different studies. Additionally, diverging conclusions use to be found among the findings while using specific approaches, posing supplementary difficulties on the clear understanding of the interrelated mechanisms taking place.

The divergence of outcomes is partly explained by the implementation of different levels of refinement for representing system's operations, together with the miscellaneous choice of methodologies, heuristics, and simplifications required for computing solutions at reasonable time. All these aspects pose challenges for the cross-validating of results between studies and limit the findings to very specific topics.

Despite these issues, there can be identified common trends among most of the recent studies on power system planning, which seems to find its origins upon the current energy policy debate. They are mostly concentrated on the need for decarbonizing the energy systems, and/or on assessing the impact of promising technological progress of new generation technologies. These two trends explicitly suggest a major paradigm shift in the industry's landscape. Among the drivers of this paradigm shifts are the important cost reductions of renewable technologies, the development of advanced fossil fuel technologies, the huge deployment of information and telecommunication (IT) technologies enabling "smarter" management of load, and the encouraging cost reductions of electric energy storage (EES) technologies.

Therefore, the common vision shared across recent studies on future power systems is the transformation towards a low carbon and "smarter" configuration of the industry, which is expected to be more or less progressive according to the hypothesis adopted when considering the factors affecting the relative competitiveness of technologies, and the severity of environmental policies considered.

Most of the recent quantitative studies on long-term system planning justify their importance, coordinate their hypothesis and ground their experimental cases around the following drivers:

EVOLVING ENERGY POLICIES

In a non-exhaustive effort for recognizing the main forces affecting current energy policy trends which, in turn, have an impact on the power system's landscape, it is possible to recognize, at least, the three following fundamental levers:

- **The increasing environmental concerns triggering ambitious CO_2 reduction policies**: the "Paris agreement on climate change"[7], but also the growing concentration levels of particulate matter affecting the air quality of major cities around the world, has urged the awareness on the climate impact and air quality issues, raising the will to take common actions to mitigate them[8]. These issues are addressed by implementing environmental policies that directly or indirectly will affect the energy industry, impacting the relative competitiveness of power generation technologies.

- **The renewed public concerns about nuclear energy after the Fukushima's accident**[9] and the growing skepticism on the profitability of new nuclear technologies due to the intensified safety requirements and recent difficulties faced by installations under construction[10]: this occurs during an epoch where most of the installed nuclear capacity is reaching the end of its technical lifespan, raising delicate energy policy questions dealing with the strategic choice of retrofitting, rebuilding

[7] The 2016's COP conference on climate change has concluded on the parties' agreement for committing to take joint actions for controlling CO2 emissions levels. Further information on this subject can be found on the official website of the United Nation's Convention on Climate Change (UNCCC): http://unfccc.int/2860.php

[8] The mitigation mechanisms include establishing carbon emission quotas, specific taxes and technology transfer instruments to reduce global carbon emissions.

[9] Detailed information the nuclear accident can be found in: (World Nuclear Association 2017; Yukiya Amano (Director General) 2015)

[10] Particularly concerns due to first-of-a-kind EPR's reactors currently being built in France (Flamanville) and UK (Hinkley Point). See the post on http://energypost.eu/epr-nuclear-reactor-fit-current-market/ for further details on this topic.

or phasing-out of existing nuclear capacity (Perrier 2017). The nuclear policy adopted during the next years will influence the power industry over the next decades due to the path dependencies and technology lock-in mechanisms affecting the development of this capital intensive industry (Arthur 1989; Kalkuhl, Edenhofer, and Lessmann 2012; Perkins 2003).

- **The persistent geopolitical concerns for fostering fuel independence and assuring energy security**: Most of the world's economies are based on the consumption of fossil fuels, which availability is constrained in the long-term due to scarcity and depletion issues, and that it is almost entirely imported from few producing countries. Thus, economies based on fossil fuels show exacerbated risk exposure due to supply steadiness and cost volatility issues in the short-term, but also due to supply shortages in the long-term. Since the 1970's oil embargos, strategies for fuel diversification were strategically adopted on non-OPEC[11] countries seeking to improve energy security levels. The increasing technical progress of renewable technologies improves the feasibility of using better distributed and cleaner energy sources (e.g., hydro, wind, solar, biomass, biogas) for electricity supply. Improved efficiency and smarter devices will also allow for a more intelligent use of resources, therefore better controlling the growing demand. Technical progress is likely to offer new possibilities for addressing long-standing energy security concerns (Hughes 2009; Johansson 2013; Tergin 2006).

EVOLVING ELECTRICITY MARKETS

The discussions on unbundling the electricity sector started during the 80's. By that time, the idea started gaining support among academics and policymakers. Countries like Chile and UK are among the pioneers of the liberalization process which started at the late 80's. They established electricity market reforms to promote ownership unbundling and competition in generation and supply (D. Newbery 2005). Since then, many other countries have followed by liberalizing, restructuring or deregulating their electricity sectors with the aim of fostering competition and solving allocation inefficiencies affecting the sector.

[11] OPEC is the intergovernmental Organization of the Petroleum Exporting Countries found in 1960.

By the late 90's and early 2000's, the European Commission passed two directives[12] paving the way for the establishment of current electricity markets. By the late 2000's, a third directive[13] was mandated to foster market competition and accelerate the liberalization process. Current European electricity markets are the product of a long process which has proven success on addressing the main objective they were conceived for, the creation of a European-wide electricity market to increase overall surplus. Newbery (2005), Joskow (2008), and Léautier and Crampes[14] (2016) expose most of the benefits and challenges of the liberalization process of the European power sector. They highlight the important efficiency improvements, but also point some of the challenges faced for a due implementation of reforms, sometimes causing important failures.

In Europe, before the market liberalization, power systems were centrally planned, and the industry was mainly conceived as a regulated monopoly across all the value chain of electricity supply. The central planner, most of the time defined as a ministry or agency, directly managed a central dispatch organism delivering short-term decisions (i.e., commitment, transmission, distribution), and it directly undertook the long-term actions dealing with capacity expansion and grid development. Thus, policy instruments were closely entangled with a directive way of driving the sector. Nevertheless, it is worth to mention that important resource allocation inefficiencies were the rule by that time (Joskow 2008), due to the intrinsic challenges related to the governance of monopolistic industries for effectively maximizing social welfare.

The electricity markets reforms have allowed the improvement of competition and resource allocation, but at the cost for decision makers of abandoning thorough instruments of long-term energy planning. Theoretically, the transition from a direct coordination of the power sector to the market-driven allocation of resources is welfare improving provided a perfect and competitive market, with negligible transaction costs. Indeed, markets are supposed to

[12] Common rules for the internal market in electricity (96/92/EC), and Directive 2003/54/EC of 26 June 2003 repealing Directive 96/92/EC.

[13] DIRECTIVE 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC

[14] The authors give a positive exposition of the outcomes obtained by the process of liberaralization of after 20 years of evolution, but they also highlight the improvements that should be addressed. The article can be found in: http://fsr.eui.eu/liberalisation-european-electricity-markets-glass-half-full/

exert an optimal coordination between short and long-term issues when properly designed and undistorted. But, the increasing environmental concerns dealing with the correction of environmental externalities have also became crucial during the last two decades of market reform.

The internalization of environmental externalities related to CO_2 emissions have consolidated into regulatory intervention through distortive energy policies. This kind of regulatory intervention have been somehow justified because of the inability of markets to address environmental issues (IEA 2006). Indeed, power markets fails addressing environmental externalities, providing service reliability and insuring security of supply. Finon and Roques (2013) adopt a critical view of the outcomes of liberalization highlighting these key issues, and advocate for a radical reform of the design of electricity markets.

The policy instruments related to decarbonizing the power systems have adopted the form of carbon taxes and/or emission quotas, as well as the promotion of new clean energy technologies with "out-of-the-market" arrangements, to minimize risk exposure of new projects involving emerging technologies. New renewable energy (RE) technologies offer encouraging solutions to relevant energy questions, and as any new evolving industry, their profitability is prone to economies-of-scale, industrial spill-overs, and learning-by-doing effects. To fill the gap between promising but uncompetitive renewable technologies, policymakers recognized the need for supporting the industry, and started offering very favorable tariffs for rewarding their infeed by the late 2000's. As a result, cost went down as RE installed capacity increased, and a sturdy industrial tissue started to grow in countries like Germany, Spain and Denmark. Although, the side-effects of pushing out-of-the-market renewable deployment has been growing since then. So, renewable generation started to cause important distortions on the price formation mechanisms of still developing electricity markets. Moreover, market distortions have been exacerbated by a very poor policy implementation of state-aids.

Current electricity market architectures are also vulnerable to the variability and uncertainty characterizing the generation patterns of wind and PV. Their infeed depends on instantaneous wind speed and solar potential, which are extremely unpredictable meteorological factors. So, their contribution for the real-time balancing of load is uncertain. It is very difficult for them to commit on supplying a firm quantity with enough certainty before delivery. Their commitment difficulties increase with the time gap between

the market settlement and the time-of-delivery required by the market, thus, the day-ahead settlement of current energy-only markets make particularly difficult the participation of VRE.

Furthermore, the cost structure of renewable technologies also represents challenges for their due integration on the current market designs. They comprise very high capital costs but almost negligible variable cost. Thus, there is a huge gap between their long-run and short-run marginal costs. Current electricity markets are based on marginal pricing schemes with no scarcity remuneration, so, their near-zero marginal cost infeed causes important shifts of the merit order stack, driving down prices (i.e., producing the so-called merit order effect), but since this infeed is also variable, following moments of scarcity may appear, suddenly producing price hikes, thus, exacerbating price volatility, which drives risk perceptions of investors. Additionally, for impeding electricity prices to reach very high levels that can harm the economics of sensitive consumers, markets have price caps triggered during scarcity situations; so, peaking units, which cost structures opposed to that of low-carbon technologies, but which presents suitable flexibility capabilities to accommodate variability, are inhibited to duly recover their full costs without scarcity pricing. As peak units are shifted out of the merit order when there is renewable infeed, their business models become completely infeasible (i.e., scissor effect). Thus, increasing variability exacerbates price volatility and may introduce capacity adequacy issues.

The increasing distortions introduced by variable renewable energies (VRE) into the markets are traduced by a distorted coordination of market players driving to market failures. Increasing episodes of negative prices, as well as the lack of incentives for investing in new generation capacity, evidence these issues. As a consequence, VRE support schemes started to be review, or retired, in most of the EU countries during the last four years (Pyrgou, Kylili, and Fokaides 2016).

From an institutional and regulatory point of view, it can be stated that the transition of power systems from a centralized approach to a fully market-driven one is still ongoing, and this transition is being challenged by increasing regulatory intervention. The distortionary effects of the implementation of clean energy policies have led policymakers to the implementation of patchwork solutions to alleviate the structural flaws of the current market design, which are not capable of properly rewarding all the services involved in the

steady and reliable supply of electricity, as well as the integration of environmental concerns.

New flexibility solutions offer some alternatives capable of alleviating these challenges, which seems proficient on improving the integration of renewable energies. They mainly comprise the better coordination of interconnections for taking advantage of geographical arbitrage; enhanced and faster generation units capable to quickly adapt to net load variations; the enhanced controllability of demand to adapt consumption according to the state of the system; the introduction of electric energy storage technologies to improve time arbitration, as well as other system services; and the review of current market designs for reducing the impact of variability through establishing closer to delivery pools, giving incentives for valuable VRE curtailment, and for duly rewarding the supply of system services.

The feasibility of these solutions is also affected by the set of policies applied dealing with the decarbonizing objectives pretended, the levels of variability introduced, and the regulatory framework in place. There is a growing awareness on these issues on the current policy debate. Indeed, the European Commission has recently launched a fourth policy directive focusing on setting the most favorable conditions for the development of these solutions[15].

SCOPE OF THESE WORKS

These are only some of the current challenges faced by the power industry and current electricity markets. These challenges open a comprehensive field of research on energy economics. The study of the impact of variability and the consideration of potential solutions to alleviate its undesirable effects are the main topics of this thesis. Thus, the motivation of this research is to shed light on these issues combining quantitative approachs from power system optimization with an inquiry methodology from energy economics.

[15] The policy package is entitled « Clean Energy For All Europeans » but is well-known as the winter package. Further details on the proposal can be found in:
https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition

The present research attempts to have a twofold contribution on the issues previously exposed including:

1. **A methodological contribution**: To offer a quantitative representation of the interactions of variability on current electricity markets with increasing shares of renewable energies. Thus, short-term and long-term issues are simultaneously considered in a modeling framework. To that end, the mathematical formulation proposed is formally introduced in Chapter I, where a detailed description of the self-developed capacity expansion model DIFLEXO is presented. Some characteristics of the modeling framework are also briefly commented in the methodological sections of Chapter II and Chapter III.

2. **An energy policy contribution**: The goal is to discuss relevant energy economics' outcomes fostering the energy policy debate. But also, to introduce possible solutions to the challenges of future power systems by analyzing case studies. These topics are emphasized in Chapter II and Chapter III, which present and discuss relevant findings related to the French power system subject to ambitious decarbonization and energy transition objectives.

Every chapter introduces the specific topics under study and offers a brief literature review of them. The diversity of issues discussed in every chapter prevents any attempt for proposing a unifying and coherent section containing general conclusions. However, every chapter presents a discussion on the most relevant findings and highlights its conclusions.

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CHAPTER I

A CAPACITY EXPANSION MODEL DEALING WITH BALANCING REQUIREMENTS, SHORT-TERM OPERATIONS AND LONG-RUN DYNAMICS

"In nature we never see anything isolated, but everything in connection with something else which is before it, beside it, under it and over it"

Johann Wolfgang von Goethe

CONTENTS OF CHAPTER I

1.1. INTRODUCTION

The power sector has undertaken a huge transformation since environmental concerns have triggered the importance of reducing CO_2 emissions of the electricity system. The fast technological development and cost decline, together with the advantageous financial support schemes and ambitious renewable portfolio standard (RPS) have triggered a fast and steady deployment of renewable energy capacity during the last decade. Wind and photovoltaic technologies, which are considered as variable renewable energies (VRE), have become the most prominent clean energy sources today.

VRE technologies are intrinsically variable and non-dispatchable by nature. Their very low marginal cost made them to be first scheduled in the merit order settlement process, leaving the so-called, net or residual load, which needs to be covered by the remaining dispatchable capacity. Therefore, when the share of VRE attains significant levels, the net demand decreases and becomes more fluctuating and less predictable. Figure 8 shows the evolution of the shape of the residual load of the French power system with increasing shares of VRE. It can be seen how variability is exacerbated, jumps on the level of demand are higher and more frequent a function of VRE penetration.

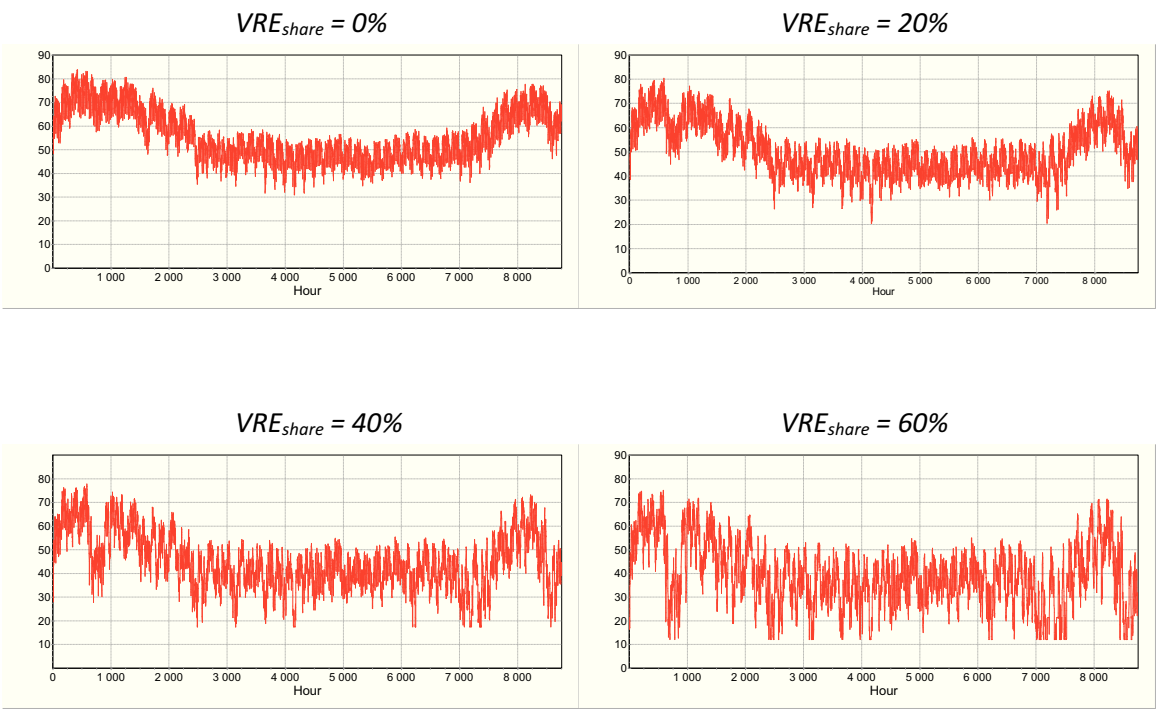


Figure 8. Effect of VRE penetration over net load including VRE curtailment. Source: Own calculations.

Existing power systems were conceived to mainly operate with fully dispatchable technologies. They were not intended to cope with high levels of variability or to balance demand and supply under high stochastic behavior. Electricity markets were neither conceived to face this new paradigm. The power markets are based on the principle of rewarding energy supplied. Little attention has been given to the supply of system services, and almost no regard has been devoted to compensating new important services such as flexibility and capacity availability until now.

Increasing shares of VRE challenges the instantaneous balance between demand and supply but also exacerbates other technical issues across the entire power system (i.e., capacity adequacy, flexibility, availability, reliability and stability); new economic questions also arise regarding the design of a market capable of sending the right signals to coordinate participants for the efficient operation of the system in the short, mid and long-run. In this way, it is mandatory to coordinate the requirements for system operations with the needs for capacity investments while contemplating enhanced system services for optimally accommodating increasing shares of VRE.

The methodology adopted in this study analyzes the power market under a resource-adequacy approach, shedding light on the links between different time horizons, considering adequate operational constraints and their associated costs to optimize the system. This study proposes a new formulation of a capacity expansion model (CEM) while considering system operations and reliability issues. It pretends to provide a better representation of existing investment models by including usually omitted system services that are expected to significantly impact the resulting optimal mix, and the resulting CO_2 emissions. It adopts a system cost perspective and a multiservice approach where a portfolio of complementary technologies is endogenously optimized considering global system requirements. A set of conventional, VRE, electric energy storage (EES) and demand-side management (DSM) capabilities can be jointly deployed regarding optimality conditions. Different energy policies can also be defined for scenario analysis (renewable portfolio standards, CO_2 tax, CO_2 emission cap, fuel cost spikes, among others). The model adopts a single node approximation of the network and no interconnections are considered.

This chapter is organized as follows: Section 1.2 presents the challenges of conceiving the power system of the future. Section 1.4 presents the framework of the study and identifies existing attempts of modeling the power system for capacity investments. Section 1.4.1 offers

a formal presentation of the model proposed in the study. Section 1.5 presents results of a case study to show some of the interrogations captured by the model. Finally, remarks and conclusions are presented in section 1.6 and 1.7.

1.2. INCREASING UNCERTAINTY ON RESIDUAL DEMAND: THE NEED FOR ENHANCING FLEXIBILITY

The power system has been experiencing a paradigm shift over the last decade. The advent of important amounts of VRE capacity on the power system has raised new questions about generation adequacy, power security and economic optimality.

Energy security issues have experienced refreshed interest within the energy research community. As exposed in (Cepeda et al. 2009), reliability and adequacy are two distinct but inherently related subjects of security of supply. Adequacy is referred as the ability of the power system to meet the aggregated power and energy levels at any time given a defined capacity margin. It can be seen as a long-term requirement related to capacity investments. Nevertheless, the low capacity contribution of VREs due to its low achievable load factors, as well as its non-dispatchable nature, furtherly harms its system value, all of which drive to renewed adequacy questions associated with supplementary capacity cost when VRE shares increases.

On the other hand, reliability has been defined as the system capability to overcome any sudden contingency such as plant or lines outages. The increasing penetration of VRE has raised additional elements to this definition which concerns system balancing needs due to recurrent non-contingency situations. This issue is mainly caused by the fluctuation of residual load given the non-negligible variability and forecasting errors of wind and solar generation. Not only variability impacts the system, the very low short-run marginal cost and the low capacity value of VRE added with their day to day, weekly and seasonal variations make peaking units to lose profits on the energy only markets, exacerbating the "missing money problem" (Joskow 2006). All of which arises additional adequacy and operability difficulties on the systems. Stranded generation assets are an evidence of the later. Just in 2013, 21 GW of gas plants were mothballed or closed in Europe out of which 8.8 GW were new plants with less than 10 years of operations. The problem is that those plants are not only necessary to assure capacity adequate levels on the system, but also to easily supply the additional flexibility required for covering up the VRE fluctuations.

Same levels of resource adequacy can be obtained with very different technology mix depending on the available resources in place. Important VRE shares are expected to continue entering into the power systems due to profitable support schemes and expected cost reductions, all of which introduces the necessity of conceiving new integration strategies. This is, additionally to supplying power and energy, sufficient levels of available capacity should be guaranteed on the system. Therefore, on the long-run, sufficient investments on power capacity, but also on flexibility capabilities, should be accomplished to allow for optimal system operability. Hence, new arbitration opportunities would appear dealing with the variability and uncertainty of net load relative to the timeframe considered.

Current power markets execute bid-based algorithms that optimize demand and supply for every hour on a rolling horizon. Bids are assumed to contain information about the VRE variability for the hours ahead but since the main revenue stream of firms comes from the energy only market (EOM), day-ahead and intraday, the main unit's rewards come from the energy supplied following the bided schedules. Flexible units, which commonly have more important marginal cost, are pushed out of the market, leaving the system with dispatch schedules with very poor flexible capabilities for settling imbalances on the real time.

On hydro dominated systems, short-run flexibility needs due to renewables are not as relevant because units can be easily dispatched, but in a context where VRE becomes more prominent, the flexibility requirements will be higher, and one day to one-hour arbitrations would arise (Druce, Buryk, and Borkowski 2016). On the long-run, higher penetrations of VRE would open the floor for new tradeoffs between scheduling generating units and flexibility options simultaneously.

Regarding the real-time scheduling, system balance is the main responsibility of TSOs. In some countries, regulators have institutionalized the role of "balancing responsible parties" to cover part of the gap of VRE forecast error via a market mechanism. In this way, market participants are prompted to exercise balancing actions and are rewarded for providing short-term flexibility for balancing purposes. Nevertheless, additional capacity margins and reserve needs are exacerbated by increasing the shares of VRE. In (Chandler 2011), the technical challenges and the associated cost of VRE generation over the system balancing actions are exposed. The balancing problem is separated into actions related to variability and actions related to intermittency of VRE. System case evaluations are conducted to estimate the maximum VRE capacity that a given power system can effectively integrate.

Even if existing power systems can manage additional amounts of variability and uncertainty, optimally integrating significant shares of VRE sources is an important issue that should be assessed when looking the investment decisions. Therefore, the flexible capabilities of the power system become the key when considering high levels of VRE.

Flexibility can be considered as the dynamic property of the system consisting on its ability to adjust to changing conditions over different timescales. Changing conditions can be either shocks in demand or supply, and can appear suddenly or be forecasted; consequently, the time of deployment of flexibility is also a crucial parameter that characterizes it. Likewise, supplying flexibility is also costly, which means that on a system perspective, it's cost should also be optimized.

The power system needs have been mutating from a capacity requirement problem to a resource-adequacy problem, where multiple products and services are needed and should be balanced over interrelated time horizons (Gottstein et al. 2012). In this way, the technical challenges introduced by VREs under current power market architectures imply understanding system services from a broader perspective to conceive new market designs and new regulatory frameworks capable of optimally driving the energy transition towards less CO_2 intensive systems.

1.3. EFFECTS OF VRE ON CAPACITY ADEQUACY AND FLEXIBILITY NEEDS

The capacity value of a power generation technology is measured by its contribution to the generation system adequacy. The European Wind Energy Association (EWEA) suggests using the "capacity credit" to measure the firm capacity of a wind power plant. It defines the capacity credit of wind as: "The reduction, due to the introduction of wind energy conversion systems, in the capacity of conventional plant needed to provide the same level of reliable electricity supply" (van Hulle et al. 2010). The Reliability requirements are computed using the Loss of Load Probability (LOLP), which is a metric that gives the probability of a shortfall at a given hour. The Loss of Load Expectation (LOLE) is then calculated and gives an idea of the magnitude and duration of probable outages over the period under study. The LOLE level is therefore the conventional metric for evaluating long-term system adequacy. Every generator capacity contributes to enhance the LOLE. The Effective Load Carrying Capability (ELCC) of different generation technologies can be then compared using this metric (Keane et al. 2011).

As explained by (Castro et al. 2008), the capacity credit of wind depends on the characteristics of the resource of the geographic area considered but also on the configuration of the incumbent power system. Their work analyses the wind capacity credit using a metric to measure its ELCC, its equivalent firm capacity and its equivalent conventional capacity. They compare these metrics on a system with and without PHS units. A probabilistic methodology is developed to constraint the system over equivalent reliability levels using the LOLE metric. Finally, the authors show how the capacity credit of wind is enhanced by the existence of flexible generation sources on the power mix.

Similar results have been exposed in (Sullivan, Short, and Blair 2008) and (D. Swider 2007), which examine the impact of storage for VRE integration using a tailored investment model. Even if these studies are more focused on the capacity value of storage technologies than wind capacity credits, both point out that storage, which is mainly a flexibility option, can lead to better integration of VRE.

The finding of these studies suggests that flexibility options affect in a positive way the capacity value of VREs. Therefore, from an adequacy point of view, capacity and flexibility may be equivalent when significant amounts of VREs are added into the system, so there should be jointly considered.

1.3.1. SYSTEM OPERABILITY AND FLEXIBILITY SERVICES SUPPLY

As stated in (Palmintier and Webster 2013), the faster dynamics of power systems with high VREs generation has exacerbated the need for very detailed representation of system operation at faster timescales within long-term CEM. Disregarding these issues "may misrepresent the true cost and performance of a particular generation mix and result in capacity mixes that are suboptimal or infeasible".

(Poudineh 2016) states that for high VRE penetrations levels, the available flexible resources may not be sufficient to manage the variations of residual load. He claims that "Traditional reliability metrics such as LOLE need to be supplemented by other metrics. Therefore, the Insufficient Ramping Resource Expectation (IRRE), a LOLE-like metric measuring net load fluctuations, could allow assessing whether planned capacity allows the system to respond to short-term flexibility needs." Therefore, by only considering the LOLE metric, there is still a risk that exacerbated variability can render the system infeasible during extreme

ramping episodes. Furthermore, variability of VREs increases load following movements of thermal power plants during regular periods, which can have important implications over the performance, operating cost and aging of power plants. Power generation technologies have different cycling capabilities; moreover load following, restarts and shut down actions have negative impacts over outages, "wear and tear", heat rates and polluting emissions, particularly for old fossil power plants (Perakis and DeCoster 2001). On a special report of the US Department of Energy (DOE) about the impacts of load following actions on power plants presented in (Myles and Herron 2012), it is claimed that fatigue and creep are synergistic causes of damages and are poorly understood by the power industry. The report shows how the Equivalent Forced Outages Rates (EFOR) increases when utilities increase unit's cycling. The authors compare baseload and load following operation modes for different technologies of different ages. The life reduction of a baseload power plant without upgrading investments for cycling can be around 17 years. Even if this effect is attenuated when plants are designed for cycling or upgrades investments are done, there is still an important loss from cycling related damages when compared with baseload operations.

In (Van Den Bergh and Delarue 2015) a unit commitment model is presented to determine the optimal scheduling of thermal units in order to meet the residual load considering cycling cost as part of the objective function. Efficiency losses due to part load operation of thermal units and, startup and shutdown costs are also considered. Thermal unit's capabilities are modeled using two set of hypotheses: first, a low-dynamic or conservative portfolio, and second, a high dynamic and more flexible one is considered assuming values available in existing literature. A case study is presented based on the German system of 2013. Comparing both portfolios, the authors find that, even if the residual system was able to follow the variability of net load in both cases, a reduction of at least 40% of the cycling cost can be achieved when ramping cost are considered on the unit commitment scheduling.

1.3.2. RELIABILITY REQUIREMENTS AND FLEXIBILITY SUPPLY

Power systems should be balanced continuously, which means, demand and supply should be equal every time and no matter the amount of uncertainty on the system. Uncertainty is not a new concept on power systems. Outages, load forecast errors and other contingencies have been regularly managed by the system operator. Even though, uncertainty due to the variability and intermittency of VRE sources can be critical at high penetration levels. New studies assess the additional need for reserve due to VRE penetration (Hirth and

Ziegenhagen 2015b; De Vos et al. 2013) and exposes the benefits of passing from a static methodology to a dynamic one for reserve sizing when uncertainty is exacerbated by VRE sources. These methodologies are based on the statistical study of unbalances based on the operating conditions of the system. Similarly, ENTSO-E suggested innovative guidelines for the dimensioning of frequency restoration reserves (FRR) in ENTSO-E (2013). It considers the uncertainty of VRE generation to settle enough amounts of FRR for covering up for forecasting errors and residual imbalances.

Moreover, detailed spectral analysis of VRE generation show the different timescale responsiveness required to cover up for the full randomness of VRE generation. In (Apt 2007) different datasets of wind farms are analyzed. The author finds that the variability of wind generation follows a large $f^{-5/3}$ Kolmogorov spectrum conveying from 30 s to 2.6 days periods, which is a wider range than that of 24h and its harmonics (12h, 8h, 6h, 4h, 3h) of peak load present in demand analysis. Based on this fitted power spectrum and regarding the ramping capabilities of conventional generators, the author states that "a linear ramp rate generator (e.i., a gas turbine) is not the optimum match for wind" variability, because in order to compensate only 1% of wind variations, the generator should be sized "twice as large as the maximum observed capacity at low frequencies". The author concludes that the best strategy to fit the wind randomness would be to use a portfolio of flexibility options to match the different portions of the Kolmogorov spectrum of wind, this is, considering fast devices such as flywheels, supercapacitors or batteries, to match short period fluctuations together with slower ramp resources to match the long-period and higher amplitude fluctuations.

The dynamics of the systems on the real-time would impact the type and the amount of capacity and flexibility investment that would optimize the system costs. In the context of a liberalized market, identifying the optimal mix would mean detecting the most valuable investment that should be fostered by an ideal market.

1.4. MODELLING CAPACITY PLANNING AND OPERATIONS

Either in regulated or in liberalized systems, finding the optimal capacity investments is useful to evaluate the efficient allocations under perfect conditions, or to accurately assess the outcomes of the current market architecture.

The goal of capacity planning is to determine the best portfolio of technologies supplying load in a reliable way and to optimally fulfill a complete set of system requirements. This task is particularly challenging since reasonable approximations used for modeling long-run decisions may produce large errors on operating costs and system reliability when applied over short timeframes. Furthermore, even if large and detailed bottom-up formulations can be expressed, restricted computational resources also constraints the complexity of the representation and may distort the result of the system under study. Attention should be given when addressing capacity planning with high VRE shares because of the enhanced difficulties to accurately representing the short-term and the real-time dynamics, as well as the locational considerations.

Capacity expansion models typically assumes a system cost perspective where operational and investment cost are accounted along the considered period. The time resolution commonly used on CEM is usually the hourly step gathered from typical days, weeks or years. The time horizon studied depends on the purpose of the model but can vary from a year to decades ahead. There is a growing consensus on literature about preferred specifications to be chosen, and time horizons to be considered for models focusing on the VRE integration in electricity systems.

Models aiming to estimate the impact of VRE on investment decisions should represent detailed operational considerations to assess, as wide as possible, the flexibility needs of the system and its associated cost. The goal is to capture the effects of VRE fluctuations at high frequencies (seconds and minutes) over long periods, such as it is currently done for maintenance scheduling (weeks) and capacity and grid investments (years) in modelling systems without VRE.

The challenge of new CEM is to bridge the gap between traditional short-term operation models and long-term investments models using very high-resolution considerations into detailed formulations to represent system operation, but still tight enough to be solved in reasonable calculation time (Carrión and Arroyo 2006; Frangioni, Gentile, and Lacalandra 2009; Hedman et al. 2009; Morales-españa 2013; Ostrowski, Anjos, and Vannelli 2012; Rajan, Takriti, and Heights 2005; Xian HE , Erik Delarue , William D ' haeseleer 2006). Research on adapting Economic Dispatch (ED), Unit Commitment (UC) and Optimal Power Flow (OPF) formulations, commonly solved to obtain day-ahead and hour-ahead programs respectively, have being seeking to couple those models with longer-term formulations like hydro

scheduling, plant maintenance and capacity expansion models (Campion et al. 2013; Palmintier 2014; Poncelet, Van Stiphout, et al. 2014; Viana and Pedroso 2013). There is also growing research on the importance of including balancing aspects and ancillary service requirements on capacity planning approaches (Hirth and Ziegenhagen 2015b; Van Stiphout et al. 2014; Van Stiphout, De Vos, and Deconinck 2017).

Breakthrough research has been produced using tight UC formulations to calculate optimal investments. A unit clustering approach to solve the large thermal UC for an entire year have being developed in (Palmintier and Webster 2011). Investments and operations are endogenously calculated in the model using a portfolio of conventional generation units that should match the residual load. The results clearly suggest that including "UC-derived" operations constraints on CEM allows evaluating operational flexibility more accurately. Even though investments in flexibility options such as batteries and DSM are disregarded, likewise the electricity network. This approach opens a wide panorama for system expansion planning with VRE.

Similarly, a technology aggregated UC formulation with a six nodes network has been developed in (Pudjianto et al. 2013) with the purpose of simulating the optimal investments in generation, storage and transmission lines for Great Britain by 2030. The model optimizes storage capacity investments while leaving the energy dimension of storage investments as an exogenous parameter. This highly detailed bottom-up approach allows the authors assessing the system value of multiple flexibility options as well as capturing the trade-offs existing between them.

The very significant size of the UC formulation with endogenous investments and grid representation makes the development of a feasible model very challenging, so recourse to heuristics is a common practice. Typical simplifications are the usage of reduced set of hours to represent the year, priority ordering, unit clustering, among others. Other alternative to simplify large problem formulations is to relax binary variables of the UC or avoiding them at all. Those speedup techniques should be wisely used to control its associated error. In (Palmintier 2014) some metrics of accuracy against computational performance are revealed for different combinations of operational constraints and formulations. A Pareto frontier is obtained showing the best possible trade-offs when incorporating operational issues on CEM. The reference formulation corresponds to a full mixed integer problem (MIP) formulation for the UC problem including investments. The author compares them in terms

of optimal capacity and total energy using the root mean square errors (RMSE) and the speedup gains associated with the heuristic applied. It is showed that the biggest source of error is the omission of operating reserves followed by not considering maintenance constraints, which is in line with what previous studies claim in (Hirth and Ziegenhagen 2015b; Van Stiphout et al. 2014); The second best formulation correspond to the case of a relaxed MIP formulation followed by a full LP formulation with planning margins[16]. These two simpler formulations allow obtaining results under the 10% RMSE for both capacity investments and energy generation obtaining calculation times from 42 to 53 times faster than the full MIP.

In (Zerrahn and Schill 2015a, 2017), a stylized greenfield dispatch and investments model using a full LP formulation is proposed to assess the value of a complete portfolio of generation, storage and flexibility options. The model minimizes the system cost and includes endogenous investments in conventional generation, renewables, power storage technologies and DSM using hourly time steps to represent an entire year. Units supply power to match an inelastic demand and the model contemplates the provision of balancing reserves. The system is modeled as a copper plate[17] and parameters are calibrated to represent the German system on the 2050 horizon. Even if balancing reserves are calculated using a static method, flexibility options appear to be valuable for the system tested on medium to large VRE penetrations levels. Investments on DSM options are valuable to supply operational flexibility, while investments in short-term storage capacity are mostly used to supply balancing reserves.

A similar metholody is proposed in (Van Stiphout, Vos, and Deconinck 2015) to study the value of investing in storage technologies for system capacity adequacy, flexibility and supply of reliability services. Three types of operational reserves are considered and are dimensioned based on the dynamic method proposed in (2013). This multiservice approach allows capturing the system value of storage for VRE integration. Results show how investments in storage units allow increasing the capacity credit of VRE, and the optimal storage capacity increases as the target for VRE increases. Under the cost assumptions

[16] Accounting for reserve supply.

[17] No network or interconnections were considered.

adopted, even in the absence of VRE, storage is competitive to support the system during high peak episodes.

Other breakthrough investments models consider existing capacities, network and interconnections to calculate the optimal mix of VRE under hypothetical technology shocks and evolving market and regulatory conditions (Grothe and Müsgens 2013; Hirth 2015; Neuhoff et al. 2008). Those types of brownfield models are usefull to evaluate mid-term energy policies towards the decarbonization of the power sector.

The following section present DIFLEXO, the model developed during this thesis. DIFLEXO adopts a bottom-up and multiservice approach to propose a full LP formulation accounting for system costs similar to that of (Zerrahn and Schill 2015a), considering a dynamic dimensioning of balancing requirements such as the suggested in (ENTSO-E 2013). The purpose of the model is to integrate the different flexibility requirements associated with high shares of VRE in a long-term optimization. The contribution of this tool is to implement a detailed representation of reservoir hydroelectric and EES technologies, as well as DSM potential, on an integrated optimization framework where new flexibility technologies are jointly evaluated on a level-playing field, considering its capabilities and associated cost.

1.4.1. MODEL PRESENTATION

The main motivation of the DIFLEXO model is to effectively differentiate multiple system requirements to find the most suitable mix of technologies that would balance the yearly dispatch at least cost. The model presentation is divided in two sections: the first sub-section introduces the long-term CEM considering short-term flexibility requirements and operating constraints; the second sub-section adds to the first the constraints related to frequency restoration reserve (FRR) balancing requirements. In this way, the model is presented in modules from which more complex formulations can be used by stacking the equations. Different formulations can be built and compared to assess the impact of system representation over the value of flexibility investments. The impact of ramping constraints, cost and reliability considerations can be evaluated when increasing VRE shares.

Element	Set	Description
t, tt	$\in \mathrm{T}$	Time slice

i	$\in$ I	Supply-side generation technologies
con	$\in$ CON $\subseteq$ I	Conventional generation technologies
vre	$\in$ VRE $\subseteq$ I	Renewable energy technologies
dre	$\in$ DRE $\subseteq$ I	Dispatchable renewable technologies
ees	$\in$ EES $\subseteq$ I	Electric energy storage technologies
$dCAES$	$\in$ DCAES $\subseteq$ EES	Electric energy storage technologies with fossil fuel support
dsm	$\in$ DSM	Demand-side technologies
lc	$\in$ LC $\subseteq$ DSM	Demand side management able to supply load curtailment
ls	$\in$ LS $\subseteq$ DSM	Demand side management able to supply load shifting

Table 1 – Sets of DIFLEXO

Parameter	Unit	Description
t_{slice}	[h]	Time slice considered
$C_i^{Capital}$	[€/GW]	Overnight cost of unit *con, res or ees*
crf_i	[€/GW]	A capacity recovery factor of production unit *con*
fc_{con}	[€/GWh$_{th}$]	Average fuel cost of conventional unit *con*
$o\&m^v{}_{con}$	[€/GWh]	Variable operation and maintenance cost of *con* unit
$o\&m^f{}_{con}$	[€/GW]	Annual fixed operation and maintenance cost of *con* unit
C^{CO2}	[€/ton]	CO_2 cost
ef_{con}	[tCO_2/GWh]	Emission factor of conventional unit
lf_{con}	[€/GW]	Load following cost of unit *con*
$o\&m^v{}_{vre}$	[€/GWh]	Variable operation and maintenance cost of *VRE* unit
$o\&m^f{}_{vre}$	[€/GW]	Annual fixed operation and maintenance cost of *RES* unit
rec_{vre}	[€/GW]	Cost of curtailment of *VRE* unit
$crf^S{}_{vre}$	[€/GW]	Capacity recovery factor of power capacity of *ees* unit
$crf^E{}_{vre}$	[€/GWh]	Capacity recovery factor of energy capacity of *ees* unit
$o\&m^v{}_{ees}$	[€/GWh]	Variable operation and maintenance cost of *ees* unit

$o\&m^{f}_{vre}$	[€/GW]	Annualized fixed operation and maintenance cost of *ees* unit
c_{lc}	[€/GW]	Cost of DSM for load curtailment
c_{ls}	[€/GW]	Cost of DSM for load shifting
δ	[%]	Load variation factor
$G^{l}_{vre,t}{}^{base}$	[GW]	Base year VRE generation of technology VRE on time t
$P_{vre}{}^{base}$	[GW]	Base year VRE capacity installed of technology *res*
$\overline{\eta_{con}}$	[GWhth/GWh]	Full load thermal efficiency of unit con
m_{con}	[-]	Part-load efficiency slope of unit con
b_{con}	[GWh_{th}]	Fuel consumption intercept
$\overline{p_{con}}$	[%]	Maximum power of technology *con* as a function of its installed capacity
$\underline{p_{con}}$	[%]	Minimum power of technology *con* as a function of its installed capacity
$r^{+}{}_{con}$	[%/min]	Ramp-up capability of technology *con*
$r^{-}{}_{con}$	[%/min]	Ramp-down capability of technology *con*
$\overline{\phi_{ees}}$	[h]	Minimum energy-power ratio of technology *ees*
$\underline{\phi_{ees}}$	[h]	Maximum energy-power ratio of technology *ees*
sd_{ees}	[%/h]	Self-discharge of storage unit *ees*
η_{ees}	[%]	Round cycle efficiency of storage unit *ees*
$\overline{e_{ees}}$	[%]	Maximum capacity for energy storage of unit *ees*
$\underline{e_{ees}}$	[%]	Minimum capacity for energy storage of unit *ees*
$\overline{s_{ees}}^{ch}$	[%]	Maximum power demand of storage unit *ees* while charging
$\overline{s_{ees}}^{dch}$	[%]	Maximum power supply of storage unit *ees* while charging
r^{ch+}_{ees}	[%/min]	Ramp-up capability of storage technology *ees* while charging

r_{ees}^{dch+}	[%/min]	Ramp-up capability of storage technology *ees* while discharging
r_{ees}^{ch-}	[%/min]	Ramp-down capability of storage technology *ees* while charging
r_{ees}^{dch-}	[%/min]	Ramp- down capability of storage technology *ees* while discharging
E_{ratio}	[%]	Fossil fuel ratio of *ees* technologies with fuel support
t_{aFRR}	[h]	Minimum required reserve supply duration for aFRR supply
t_{mFRR}	[h]	Minimum required reserve supply duration for mFRR supply
$\overline{dsm}_{lc}$	[%]	Maximum part of load available for load curtailment lc
R	[h]	Number of recovery periods after curtailment
L_{lc}	[h]	Number of consecutive periods a *lc* can be activated
L_{ls}	[h]	Radius of the load shifting window
$\overline{dsm}_{ls}^{up}$	[%]	Maximum part of load available for load upward shifting ls
$\overline{dsm}_{ls}^{do}$	[GW]	Maximum part of load available for load downward shifting ls
$P^{Usize}{}_{con}$	[GW]	Unitary size of conventional unit con
$\varepsilon_l^{aFRR_{up}}; \varepsilon_l^{aFRR_{do}}$	[%]	Average forecasting RMSE of demand (5% tolerance)
$\varepsilon_{res}^{aFRR_{up}}; \varepsilon_{res}^{aFRR_{do}}$	[%]	Average forecasting RMSE of VRE generation (5% tolerance)
$\varepsilon_l^{mFRR_{up}}; \varepsilon_l^{mFRR_{do}}$	[%]	Average forecasting RMSE of demand (1% tolerance)
$\varepsilon_{res}^{mFRR_{up}}; \varepsilon_{res}^{mFRR_{do}}$	[%]	Average forecasting RMSE of demand (1% tolerance)
δ^{up}	[%]	Maximum regulation up capability of technology *con*
δ^{do}	[%]	Maximum regulation down capability of technology *con*
$\delta^{up^{sp}}$	[%]	Maximum spinning up capability of technology *con*

δ^{dosp}	[%]	Maximum spinning down capability of technology *con*
θ_{res}	[%]	Yearly share of renewable energy (RE goal)

Table 2 –Parameters of DIFLEXO

Variable	Unit	Description
I_{con}	[M€]	Annuitized overnight cost of production unit *con*
MB_{con}	[M€]	Annuitized *con* unit mothballing cost
$F_{con,t}$	[M€]	Total fuel cost of production unit *con*
$O\&M_{con,t}$	[M€]	Operation and maintenance cost of conventional unit *con*
$CO2_{con,t}$	[M€]	CO_2 emission cost of conventional unit *con*
$\Delta G_{con,t}$	[M€]	Load following cost of conventional unit *con*
LF_{con}	[M€]	Load following cost of unit *con*
P_i^{ini}	[GW]	Initial installed capacity of technology *i*
P_i^{inv}	[GW]	New capacity investments of technology *i*
P_i^{MB}	[GW]	Mothballed capacity of technology *i*
$G^l{}_{con,t}$	[GW]	Generation level of conventional unit *con*
$FC_{con,t}$	[GWh_{th}]	Linearized part-load fuel consumption of production unit con
$G^+{}_{con,t}$	[GW]	Generation increase of unit *con* in hour *t*
$G^-{}_{con,t}$	[GW]	Generation decrease of unit *con* in hour *t*
I_{vre}	[M€]	Annuitized overnight cost of VRE unit *res*
MB_{vre}	[M€]	Annuitized VRE mothballing cost
$O\&M_{vre,t}$	[M€]	Operation and maintenance cost of RE unit *res*
P_{vre}	[GW]	Total installed power of VRE units
$G^l{}_{vre,t}$	[GW]	Generation level of VRE unit *res*

$REC_{vre,t}$	[M€]	Curtailment cost of VRE unit *res*
$G^{cu}_{vre,t}$	[GW]	Power curtailed of V*RE* unit on hour *t*
I_{ees}	[M€]	Annuitized overnight cost of storage unit *ees*
MB_{ees}	[M€]	Annuitized *ees* mothballing cost
$O\&M_{ees,t}$	[M€]	Operation and maintenance cost of *ees* units
S^{ini}_{ees}	[GW]	Initial installed power capacity of storage technology *ees*
S^{inv}_{ees}	[GW]	New power capacity investments of storage technology *ees*
S^{MB}_{ees}	[GW]	Mothballed power capacity of storage technology *ees*
E^{ini}_{ees}	[GW]	Initial installed energy capacity of storage technology *ees*
E^{inv}_{ees}	[GW]	New power energy investments of storage technology *ees*
E^{MB}_{ees}	[GW]	Mothballed energy capacity of storage technology *ees*
$S^{ch}_{ees,t}$	[GW]	Power demand by storage unit *ees* on time t
$S^{dch}_{ees,t}$	[GW]	Power supply of storage unit *ees* on time t
$EES^{CT}_{ees,t}$	[GW]	Power supply of storage unit *ees with fossil fuel support* on time t
$S^{ch+}_{ees,t}$	[GW/h]	Demand increase of storage unit *ees* in hour *t* while charging
$S^{ch-}_{ees,t}$	[GW/h]	Supply increase of storage unit *ees* in hour *t* while charging
$S^{dch+}_{ees,t}$	[GW/h]	Demand increase of storage unit *ees* in hour *t* while discharging
$S^{dch-}_{ees,t}$	[GW/h]	Supply increase of storage unit *ees* in hour *t* while discharging
$E^{l}{}_{ees,t}$	[GW]	Storage level of technology ees
$DSM_{lc,t}$	[GW]	Hourly cost of DSM for load curtailment
$DSM^{l}{}_{lc,t}$	[GW]	DSM curtailment of load *lc* on time t
$DSM_{ls,t}$	[GW]	Hourly cost of DSM for load Shifting
$DSM^{up}_{ls,t}$	[GW]	DSM shifting up *ls* on time t

$DSM_{ls,t,tt}^{do}$	[GW]	DSM shifting up *ls* on time *tt* from *t*
NL_t	[GW]	Net load on time t
LL_t	[GW]	Loss of load on time t
$G_{con,t}^{aFRR_{up}}$	[GW]	Contribution of *con* units to *mFRR* up supply
$G_{con,t}^{aFRR_{do}}$	[GW]	Contribution of *con* unit to *aFRR* down supply
$G_{con,t}^{mFRR_{up}^{sp}}$	[GW]	Contribution of spinning *con* unit to *mFRR* up supply
$G_{con,t}^{mFRR_{do}^{sp}}$	[GW]	Contribution of spinning *con* unit to *mFRR* down supply
$G_{con,t}^{mFRR_{up}^{nsp}}$	[GW]	Contribution of non-spinning *con* unit to *mFRR* up supply
$S_{ees,t}^{ch,aFRR_{up}}$	[GW]	Contribution of *ees* unit to *aFRR* up supply while charging
$S_{ees,t}^{ch,mFRR_{up}}$	[GW]	Contribution of *ees* unit to *mFRR* up supply while charging
$S_{ees,t}^{ch,aFRR_{do}}$	[GW]	Contribution of *ees* unit to *aFRR* down supply while charging
$S_{ees,t}^{ch,mFRR_{do}}$	[GW]	Contribution of *ees* unit to *mFRR* down supply while charging
$S_{ees,t}^{dch,aFRR_{up}}$	[GW]	Contribution of *ees* unit to *aFRR* up supply while discharging
$S_{ees,t}^{dch,mFRR_{up}}$	[GW]	Contribution of *ees* unit to *mFRR* up supply while discharging
$S_{ees,t}^{dch,aFRR_{do}}$	[GW]	Contribution of *ees* unit to *aFRR* down supply while discharging
$S_{ees,t}^{dch,mFRR_{do}}$	[GW]	Contribution of *ees* unit to *mFRR* down supply while discharging
$Q_t^{aFRR_{up}}$	[GW]	Total *aFRR* up required on time *t*
$Q_t^{aFRR_{do}}$	[GW]	Total *aFRR* down required on time *t*
$Q_t^{mFRR_{up}}$	[GW]	Total *mFRR* up required on time *t*
$Q_t^{mFRR_{do}}$	[GW]	Total *mFRR* down required on time *t*

Table 3 –Variables of DIFLEXO

OBJECTIVE FUNCTION

The DIFLEXO model adopts a LP formulation for the investment and dispatch problem. CAPEX[18] and OPEX[19] are considered together with ramping cost, efficiency penalties for partial load operation, wear and tear cost of units, CO_2 emission cost and VRE curtailment cost. The objective function presented in (1) embodies the total systems cost of the power system considering aggregated agents with perfect foresight. This hypothesis is equivalent than assuming a market with perfect competition and no information asymmetries, no transaction cost and other issues such as strategic behavior and market power.

Total system cost is therefore composed by the sum of annuitized costs of power generation and storage capacity investments and/or mothballing, cost for enabling DSM's capabilities and running cost incurred for using these capacities along the considered period.

To capture the impact of flexibility needs while capacity planning; equation (1) is minimized over a full year using hourly time slices. Investment and dispatch decisions are computed simultaneously and in an endogenous manner. Power demand is considered as price-inelastic but can be deferred or curtailed subject to the technical restrictions of DSM capabilities considered.

$$\begin{aligned} Y = & \sum_{con}(I_{con} + MB_{con}) + \sum_{con}\sum_{t}\left(F_{con,t} + O\&M_{con,t} + CO2_{con,t} + \Delta G_{con,t}\right) \\ & + \sum_{vre}(I_{vre} + MB_{vre}) + \sum_{res}\sum_{t}\left(O\&M_{vre,t} + VREC_{vre,t}\right) \\ & + \sum_{ees}(I_{ees} + MB_{ees}) + \sum_{ees}\sum_{t}\left(F_{ees,t} + O\&M_{ees,t} + CO2_{ees,t}\right) \\ & + \sum_{DSM} I_{DSM} + \sum_{lc}\sum_{t} O\&M_{lc,t}^{DSM} + \sum_{ls}\sum_{t} O\&M_{ls,t}^{DSM} \end{aligned} \tag{1}$$

[18] Capital expenditures

[19] Operational expenditures

COST DEFINITIONS

Investment cost is accounted by using capacity recovery factors[20] (*crf*), also called equivalent annual cost (EAC). Technology specific crf_i are inputs of the model. Equation (2) shows the way investment cost is calculated for conventional and VRE technologies.

$$I_i = crf_i \, P_i^{inv} \qquad \forall \, i \tag{2}$$

$$crf_i = \frac{WACC_i \, C_i^{Capital}}{1-(\frac{1}{1+WACC_i})^{a_i^{life}}} \qquad \forall \, i \tag{3}$$

Regarding EES investments, power and energy capacity are considered separately. These two dimensions of energy storage units are presented in equation (4), which comprises independent *crf* for each one. The differentiation of power and capacity investments for storage technologies, avoiding the usage a fixed ratio, allows an improved dimensioning of storage parameters according to system's needs. Equation (5) relates these two storage dimensions using a minimum and maximum technology related storage autonomy factor. This procedure allows the model to endogenously optimize EES investments into power and energy capacity independently, considering both dimensions in the resulting optimal investment. This choice is expected to enhance the system value of EES technologies since it disentangles, to the technical limits describing every technology, the additional power to energy capabilities and vice versa. Otherwise, every investment in storage capacity would entail an associated energy storage cost, which would deteriorate the relative competitiveness of EES technologies compared to single dimension flexibility options. Thus, this approach loosens the allocation of restrictions for storage on the optimal investment portfolio.

$$I_{ees} = crf^S{}_{ees} \, S_{ees}^{inv} + crf^E{}_{ees} E_{ees}^{inv} \qquad \forall \; ees \tag{4}$$

$$S_{ees}\underline{\phi_{ees}} \leq E_{ees} \leq S_{ees}\overline{\phi_{ees}} \qquad \forall \; ees \tag{5}$$

[20] They are estimated using overnight cost, lifespan and weighted average cost of capital (WACC).

Similarly, enabling dynamic DSM capabilities involve investing on adequate infrastructure according to Bradley, Leach, and Torriti (2013) and Strbac (2008). Namely, the energy management system (EMS) or smart metering system as outlined by the UK Department for Energy and Climate Change (2014). The elements considered on the overnight cost for enabling DSM capabilities are supposed to be the same for both load curtailment and load shifting services; so, once they are accounted for they enable both services. The EMS cost is mainly user specific (e.i. the smart meter, displays, communication system and installation), but there are also important shared cost taking place[21]. For the sake of simplicity, investment costs are represented in the model as aggregated cost allowing resource availability, but which usage is intrinsically constrained by operational limits at the consumer level and by the grid. This is represented on equation (6), where DSM represents the maximum power the EMS can handle.

$$I_{DSM} = crf_{DSM}\ DSM \qquad \forall\ ees \tag{6}$$

Running costs of conventional units are divided into fuel cost, O&M cost, CO_2 cost and load following cost. The cost for mothballing existing capacity was introduced in a simplified way assuming it as a fraction of the overnight cost (e.g., 5%) for every technology under consideration. Equation (8) accounts for the fuel cost of conventional units where $Fuel_{con,t}$ is the instantaneous fuel consumed corrected by the part-load efficiency, fc_{con} is the average cost of fuel consumed by unit "con". Equation (9) accounts for fixed and variable operational and maintenance cost. CO_2 cost deals with fuel specific emission factors and part-load efficiencies as expressed in equation (10). Load following costs are defined in equation (11) as proportional to the absolute value of the difference of the synchronized power of two consecutives periods.

$$MB_i = 0.05\ crf_i P_i^{MB} \qquad \forall\ i \in con \cup vre \tag{7}$$

$$F_{con,t} = Fuel_{con,t}\ fc_{con} \qquad \forall\ con \tag{8}$$

$$O\&M_{con,t} = \mathrm{o\&m^v}_{con}\ G^l{}_{con,t} + \mathrm{o\&m^f}_{con}\ P_{con} \qquad \forall\ con \tag{9}$$

[21] This are the centralized Data and Communications Company (DCC) and other IT's related costs.

$$CO2_{con,t} = \mathrm{C}^{CO2}\ \mathrm{ef}_{con}\, Fuel_{con,t} \qquad \forall\ con \tag{10}$$

$$\Delta G_{con,t} = \left| G^{l}{}_{con,t} - G^{l}{}_{con,t-1} \right| \mathrm{lf}_{\mathrm{con}} \qquad \forall\ con \tag{11}$$

Similarly, than for generation technologies, the mothballing cost of storage technologies are accounted in equation (12). Equations (13) and (14) accounts for fuel consumption and CO2 emissions cost of EES technologies using fossil fuel support (e.g., diabatic CAES). Variable and fixed O&M cost of EES units are represented in equation (15). Storage units can be charging or discharging at the same time if needed. Equation (15) accounts for the associated cost of both uses independently. VRE curtailment is also included as a source of flexibility, and even if there is no technical cost associated with curtailing renewables, equation (16) accounts for a possible VRE curtailment cost if any.

$$MB_{ees} = 0.05\left(crf^{E}{}_{ees}\ S^{MB}_{ees} + crf^{E}{}_{ees} E^{MB}_{ees}\right) \qquad \forall\ ees \tag{12}$$

$$F_{ees,t} = Fuel_{ees,t}\, fc_{ees} \qquad \forall\ ees \in dCAES \tag{13}$$

$$CO2_{ees,t} = \mathrm{C}^{CO2}\ \mathrm{ef}_{ees}\, Fuel_{ees,t} \qquad \forall\ ees \in dCAES \tag{14}$$

$$O\&M_{ees,t} = \mathrm{o\&m^{v}}_{ees}\left(S^{ch}_{ees,t} + S^{dch}_{ees,t}\right) + o\&m^{f}{}_{ees}\, S_{ees} \qquad \forall\ ees, t \tag{15}$$

$$REC_{vre,t} = G^{cu}_{vre,t}\ \mathrm{rec}_{vre} \qquad \forall\ vre \tag{16}$$

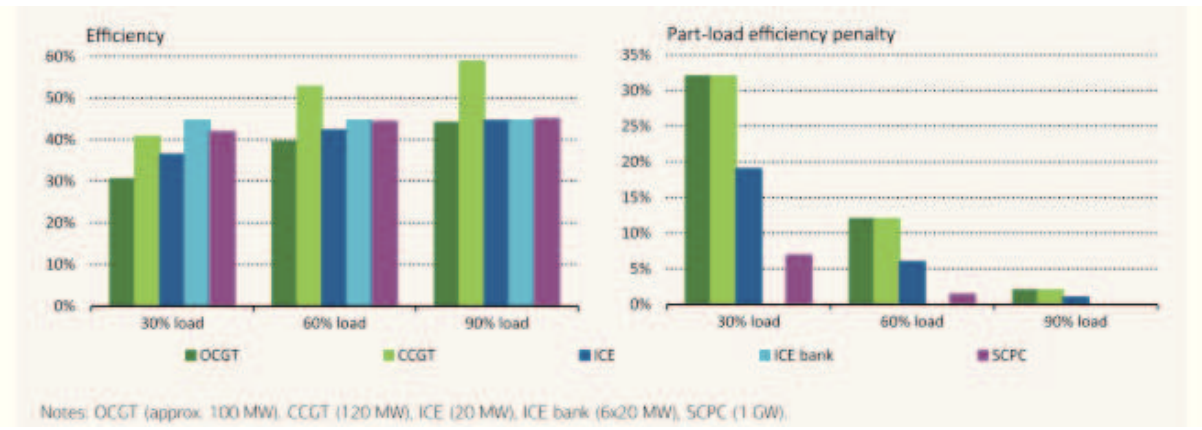


Figure 9. Efficiency Vs. load for different gas power generation technologies. Source: (International Energy Agency 2014)

The fuel consumption due to part-load generation is linearly approximated as presented on equation (17). Equations (18) and (19) are computed from technical data of generation units and uses exogenous parameters of the model (see Figure 9). Replacing and rearranging terms into equation (17) results on equation (20) which articulates the hourly fuel consumption as a function of synchronized power and installed capacity.

$$Fuel_{con,t} = G^{l}{}_{con,t}\, m_{con} + b_{con} \qquad \forall\ con \tag{17}$$

$$m_{con} = \frac{\Delta FC_{con}^{max}}{\Delta P_{con}^{max}} = \frac{\dfrac{P_{con}\,\overline{p_{con}}}{\overline{\eta_{con}}} - \dfrac{P_{con}\,\underline{p_{con}}}{\underline{\eta_{con}}}}{P_{con}\,\overline{p_{con}} - P_{con}\,\underline{p_{con}}} = \frac{\dfrac{\overline{p_{con}}}{\overline{\eta_{con}}} - \dfrac{\underline{p_{con}}}{\underline{\eta_{con}}}}{\left(\overline{p_{con}} - \underline{p_{con}}\right)} \tag{18}$$

$$b_{con} = \left(\frac{\overline{p_{con}}}{\overline{\eta_{con}}} - m_{con}\,\overline{p_{con}}\right) P_{con} \tag{19}$$

$$Fuel_{con,t} = \left(G^{l}{}_{con,t} - \overline{p_{con}}\,P_{con}\right) m_{con} + P_{con}\frac{\overline{p_{con}}}{\overline{\eta_{con}}} \qquad \forall\ con \tag{20}$$

Demand-side management capabilities, namely load curtailment (*lc*) and load shifting (*ls*) have particular O&M cost dealing with activation cost, EMS maintenance, DCC operational expenditures among others. Maximum capacity, activation cost and recovery time are inputs of the model. Equation (21) and (22) account for the operational cost of activating each of these services.

$$O\&M_{lc,t}^{DSM} = DSM^{l}{}_{lc,t}\, o\&m_{lc} \qquad \forall\ t, lc \tag{21}$$

$$O\&M_{ls,t}^{DSM} = DSM_{ls,t}^{up}\ \mathrm{o\&m}_{ls} \qquad \forall\ t, ls \tag{22}$$

DEFINING VRE GENERATION, NET LOAD AND ENERGY MARKET BALANCE

Investments in VRE capacity are endogenously computed by the model. As presented in equation (23), the hourly production $G^{l}{}_{vre,t}$ is obtained by resizing the unitary base year hourly generation by the net capacity added. Therefore, it is convenient that the base year adopted to represent VRE generation comes from a statistically representative year obtained from historical data.

$$G^{l}{}_{vre,t} = \frac{\mathrm{G}^{\mathrm{l}}{}_{vre,\mathrm{t}}{}^{\mathrm{base}}}{\mathrm{P}_{vre}{}^{\mathrm{base}}} \left(P_{vre}^{ini} + P_{vre}^{inv} - P_{vre}^{MB}\right) \qquad \forall\, vre, t \tag{23}$$

Consequently, the net load (NL_t) is defined as the result of applying a variation coefficient (δ<0 demand contraction, δ>0 demand expansion) to the hourly load of the base year (i.e. allowing for a homothetic transformation of demand) and withdrawing from it the net VRE generation, assumed as fatal supply, and VRE infeed[22].

$$NL_t = \mathrm{L}_{\mathrm{t}}^{\mathrm{base}}\,(1+\delta) - \sum_{vre}\left(G_{vre,t}^{l} - G_{vre,t}^{cu}\right) - \sum_{dre}\left(G_{dre,t}^{l}\right) \qquad \forall\, t \tag{24}$$

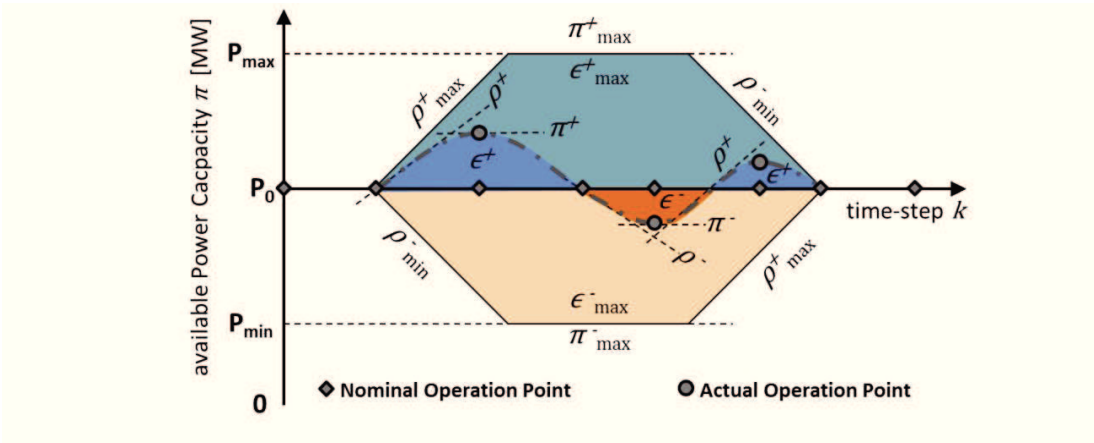
Therefore, the balancing equation of the energy market is formulated as:

$$NL_t = \sum_{con} G^{l}{}_{con,t} + \sum_{ees}\left(S_{ees,t}^{dch} - S_{ees,t}^{ch}\right) + \sum_{ees \in dCAES} EES_{ees,t}^{CT} \qquad \forall\, \boldsymbol{t} \tag{25}$$

$$+ \sum_{lc} DSM^{l}{}_{lc,t} + \sum_{ls}\sum_{tt=t-L_{ls}}^{tt=t+L_{ls}} DSM_{ls,tt,t}^{do} - \sum_{ls} DSM_{ls,t}^{up}$$

[22] DRE technologies are composed by biomass, biogas, marine energy sources among others. They are considered exogenously due to their case specific potential. For the sake of simplicity, they are not part of the investment portfolio but assigned discretionally according historical data.

OPERATIONAL CONSTRAINTS OF CONVENTIONAL UNITS



** Ramp-rate (ρ), Power (π) and Energy (ε)*

*Note: nomenclature of the figure is translated as follows : $\boldsymbol{\pi}^{+}$: $\overline{\mathbf{p}_{\mathbf{con}}}$, $\boldsymbol{\pi}^{-}$: $\underline{\boldsymbol{p}_{\mathbf{con}}}$, $\boldsymbol{\rho}^{-}_{min}$: $\boldsymbol{r}^{-}$, $\boldsymbol{\rho}^{+}_{max}$: $\boldsymbol{r}^{+}$

Figure 10. Flexibility metrics in power system operations. Source: (Ulbig and Andersson 2015).

Power capacity can be given either by initial conditions on the case of a brownfield scenario or by investing in new capacity for a greenfield study. In the case where there is over capacity on the system, it is possible to mothball part of the capacity if this is proven economically optimal given retirement costs. Equation (26) computes capacity investments and mothballing decisions defining the net capacity of every technology on the system.

$$P_{con} = P_{con}^{ini} + P_{con}^{inv} - P_{con}^{MB} \qquad \forall\, con \tag{26}$$

Equation (27) defines the power supply limits of conventional units as a function of total available capacity. This is particularly important for dimensioning episodes. During scarcity episodes, the short-run marginal cost would be able to coincide with the long-run marginal cost that would reflect the need for additional capacity investments. It is to be noted that the meaning of scarcity adopts a broad sense in equation (27) since it not only accounts for situation of supply scarcity when the right-hand side of the former equation is binding, but also, takes considers the opposite situation where minimum load is binding, which is described by the left-hand side of the equation as kind of a must-run condition. Thus, during moments of low demand and high renewable energy infeed, this condition would be decisive for the dimensioning of the DSM or EES stock required to overcome such episodes.

$$\underline{p_{con}} P_{con} \leq G^{l}{}_{con,t} \leq \overline{p_{con}} P_{con} \qquad \forall\, t, con \tag{27}$$

The ramping constraints of conventional units are defined in equation (28). Ramping up ($G^{+}{}_{con,t}$) and down ($G^{-}{}_{con,t}$) restrictions of conventional units are given by equations (29) and (30), where parameters $r^{+}{}_{con}$ and $r^{-}{}_{con}$ are the maximum ramp-up and down per minute of conventional units respectively. In such a way, ramping cost have a short-term component presented in equation (11) and a long-run cost associated with capacity as described by equations (29) and (30).

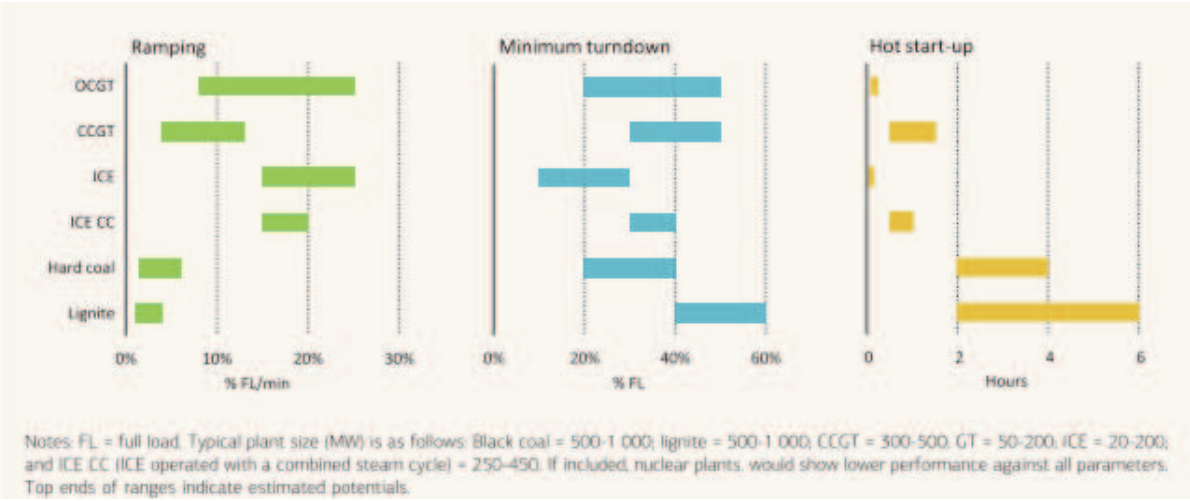


Figure 11. Ranges of flexibility parameters for thermal electricity generation technologies. Source: (International Energy Agency 2014)

$$-G^{-}{}_{con,t} \leq G^{l}{}_{con,t} - G^{l}{}_{con,t-1} \leq G^{+}_{con,t} \qquad \forall\, t, con \tag{28}$$

(w/o reserve requirements)

$$G^{+}{}_{con,t} \leq r^{+}{}_{con}\, P_{con}\, t_{slice} \qquad \forall\, t, con \tag{29}$$

$$G^{-}{}_{con,t} \leq r^{-}{}_{con}\, P_{con}\, t_{slice} \qquad \forall\, t, con \tag{30}$$

The level of reservoir hydro plants depends on the seasonal inflows and water availability. Historic meteorological data available for water inflows is given on a weekly basis, then, the optimization of reservoir hydro is formulated using weekly steps and assumes that total inflows (i.e., the entire inflow of the week) occurs at the first hour of the week under. The energy conservation equations for the first and succeeding weeks are exposed in equations (31) and (32) respectively. The average water level on the first week ($H2O_{w}^{avg}$) is normalized

by the installed capacity ($\overline{P_{hydro}}$), which allows to represent water levels as a function of investments on hydro capacity and water inflows. Inflows and water used for electricity generation are similarly normalized by capacity. Equation (33) controls the minimum and maximum water levels.

$$H2O_w^l = \frac{H2O_w^{avg}}{\overline{P_{hydro}}} P_{hydro} + \frac{H2O_w^{inflow}}{\overline{P_{hydro}}} P_{hydro} - \sum_{t \in w} Fuel_{hydro,t} \qquad if \quad w = 1 \tag{31}$$

$$H2O_w^l - H2O_{w-1}^l = \frac{H2O_w^{inflow}}{\overline{P_{hydro}}} P_{hydro} - \sum_{t \in w} Fuel_{hydro,t} \qquad if \quad w > 1 \tag{32}$$

$$\underline{H2O} < H2O_w^l \leq \overline{H2O} \qquad \forall \quad w \tag{33}$$

OPERATIONAL CONSTRAINTS OF STORAGE UNITS

EES units are among the main flexibility sources considered. Charging and discharging modes are represented independently for every technology. This allow simulating different storage capabilities, as for example: deploying fast response from Li-Ion batteries for balancing purposes while charging a bulk energy storage unit.

Equations (34) and (35) are the EES equivalent to equation (26) for conventional units. They define the net capacity of energy and power of EES units available in the system. Equation (36) represents the energy conservation equation for EES units. It shows the dynamics of EES units and considers a technology based self-discharge term (sd_{ees}). It also accounts for energy losses due to cycling.

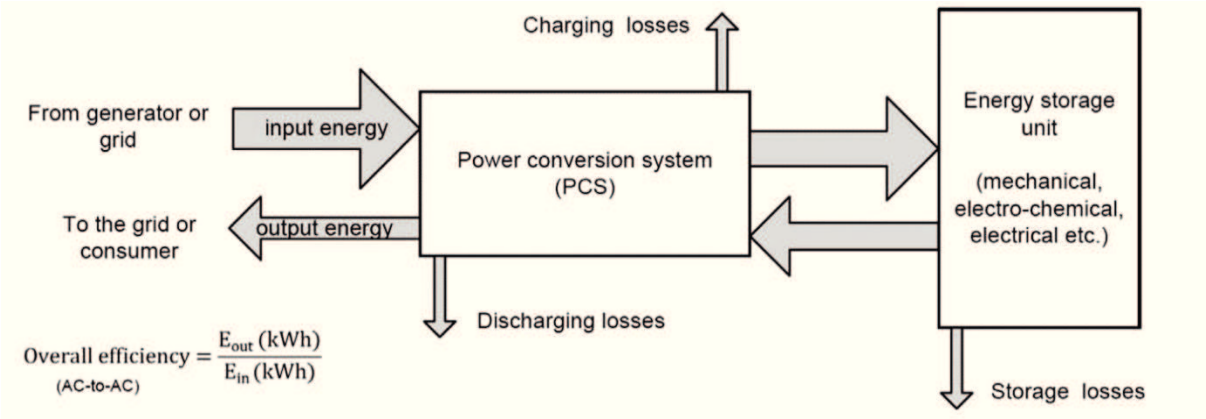


Figure 12. Components and energy flows of EES technologies. Source: (Zakeri and Syri 2015).

Equation (37) restricts the level of energy stored as a function of available capacity. Equation (38) - (39) are equivalent to equation (27) but applied to storage units when assuming charging and discharging modes separately, thus, assigns long-run cost related to investments in storage. Furthermore, it restricts the net flexibility supply from storage to fully charge and discharge the same unit at the same time.

$$E_{ees} = E_{ees}^{ini} + E_{ees}^{ini} - E_{ees}^{MB} \tag{34}$$

$$S_{ees} = S_{ees}^{ini} + S_{ees}^{ini} - S_{ees}^{MB} \tag{35}$$

$$E^{l}{}_{ees,t} = E^{l}{}_{ees,t-1}\,(1 - sd_{ees}) + \left(\sqrt{\eta_{ees}}\;S_{ees,t-1}^{ch,} - \frac{S_{ees,t-1}^{dch}}{\sqrt{\eta_{ees}}}\right) t_{slice} \qquad \forall\, t, ees \tag{36}$$

$$\underline{e_{ees}}\,E_{ees} \leq E^{l}{}_{ees,t} \leq \overline{e_{ees}}\,E_{ees} \qquad \forall\, t, ees \tag{37}$$

$$S_{ees,t}^{ch} \leq S_{ees}\;\overline{s_{ees}}^{ch} \qquad \forall\, t, ees \tag{38}$$

$$S_{ees,t}^{dch} \leq S_{ees}\;\overline{s_{ees}}^{dch} \qquad \forall\, t, ees \tag{39}$$

Ramping capabilities of storage units are represented in equations (40) and (41). They limit the power supply and demand of EES units while charging and discharging following the same reasoning presented in equation (28) for conventional units. The articulation of ramping capabilities with capacity investments builds the bridge between short-run

operational constraints with long-run marginal costs[23]. Equations (42) - (45) restricts the ramping up/down for charging and discharging modes respectively.

$$-S_{ees,t}^{ch-} \leq S_{ees,t}^{ch} - S_{ees,t-1}^{ch} \leq S_{ees,t}^{ch+} \quad \forall\, t, ees \tag{40}$$

$$-S_{ees,t}^{dch-} \leq S_{ees,t}^{dch} - S_{ees,t-1}^{dch} \leq S_{ees,t}^{dch+} \quad \forall\, t, ees \tag{41}$$

$$S_{ees,t}^{ch+} = r_{ees}^{ch+}\, S_{ees}\, t_{slice} \quad \forall\, t, ees \tag{42}$$

$$S_{ees,t}^{dch+} = r_{ees}^{dch+}\, S_{ees}\, t_{slice} \quad \forall\, t, ees \tag{43}$$

$$S_{ees,t}^{ch-} = r_{ees}^{ch-}\, S_{ees}\, t_{slice} \quad \forall\, t, ees \tag{44}$$

$$S_{ees,t}^{dch-} = r_{ees}^{dch-}\, S_{ees}\, t_{slice} \quad \forall\, t, ees \tag{45}$$

Unlike conventional generation technologies, for EES units to supply power, enough energy levels should be granted to be eligible for commitment on discharging mode. Inversely, enough capacity for storing energy should exist at any time for an EES unit to be able to take power from the grid on charging mode. Equations (46) and (47) describe the later restrictions.

$$\left(S_{ees,t}^{ch}\, t_{slice}\right)\sqrt{\eta_{ees}} \leq E_{ees} - E^{l}{}_{ees,t-1} \quad \forall\, t, ees \tag{46}$$

$$\frac{S_{ees,t}^{dch}\, t_{slice}}{\sqrt{\eta_{ees}}} \leq E^{l}{}_{ees,t-1} \quad \forall\, t, ees \tag{47}$$

Moreover, the storage representation presented below should be enlarged to characterize EES technologies using fuel to support its operation (e.g., diabatic CAES). This is particularly important because, even if the fuel usage of these EES technologies uses to be insignificant compared to that of a thermal power plant, under highly CO_2 constrained and/or higher fuel cost scenarios, the competitiveness of storing electricity with such technologies would be

[23] This is particularly useful to differentiate slow and fast storage technologies in terms of cost and capabilities.

significantly threatened by an upsurge of short run marginal costs. For instance, diabatic *CAES* (*dCAES*) technologies are simulated by using the analogy of a decoupled turbo-expander with a reservoir[24] which cycling process works as follows: First, the charging stage consist on a compression stage exclusively involving the usage of the electrical compressor, transforming the electric power to compressed air (mainly during off-peak periods using low value electricity). The charging capacity is described by eq. (48). Second, the compressed air is stored on the storage reservoir[25] for later use. The reservoir capacity is defined by eq. (49). Third, the expansion stage in which the compressed air is released from the reservoir and passes through a pre-heating step driven by the *CT* to be consequently expanded on the turbine, which transform the pressurized high temperature air (i.e., high enthalpy air) back to electricity. This stage is defined by eq.(50). It can be noted that these hybrid EES technologies are very similar to the pure EES previously introduced but comprises an additional term for the discharging stage which is added to the rated discharge capacity, where the share of the *dCAES* discharge capacity corresponding to the pre-heating step is represented by $EES_{ees,t}^{CT}$, while the share of the compressed air correspond to $S_{ees,t}^{dch}$. Fuel consumption is presented in (51), where E_{ratio} is an exogenous parameter describing the typical ratio of gas consumption over total power discharged.

$$S_{ees,t}^{ch} \leq S_{ees}\ \overline{s_{ees}}^{ch} \qquad \forall\, t, ees \in dCAES \tag{48}$$

$$\underline{e_{ees}}\, E_{ees} \leq E^{l}_{ees,t} \leq \overline{e_{ees}}\, E_{ees} \qquad \forall\, t, ees \in dCAES \tag{49}$$

$$\left(EES_{ees,t}^{CT} + S_{ees,t}^{dch}\right) \leq S_{ees}\ \overline{s_{ees}}^{dch} \qquad \forall\, t, ees \in dCAES \tag{50}$$

$$Fuel_{ees,t} = \frac{EES_{ees,t}^{CT}}{(1 - E_{ratio})} \qquad \forall\, t, ees \in dCAES \tag{51}$$

OPERATIONAL CONSTRAINTS OF DSM UNITS

Load curtailment and load shifting are the two types of DSM services considered in the model. The load curtailment service is modeled as a scheduled prompt decrease in demand

[24] For a more detailed explanation of CAES technologies visit: http://energystorage.org/compressed-air-energy-storage-caes

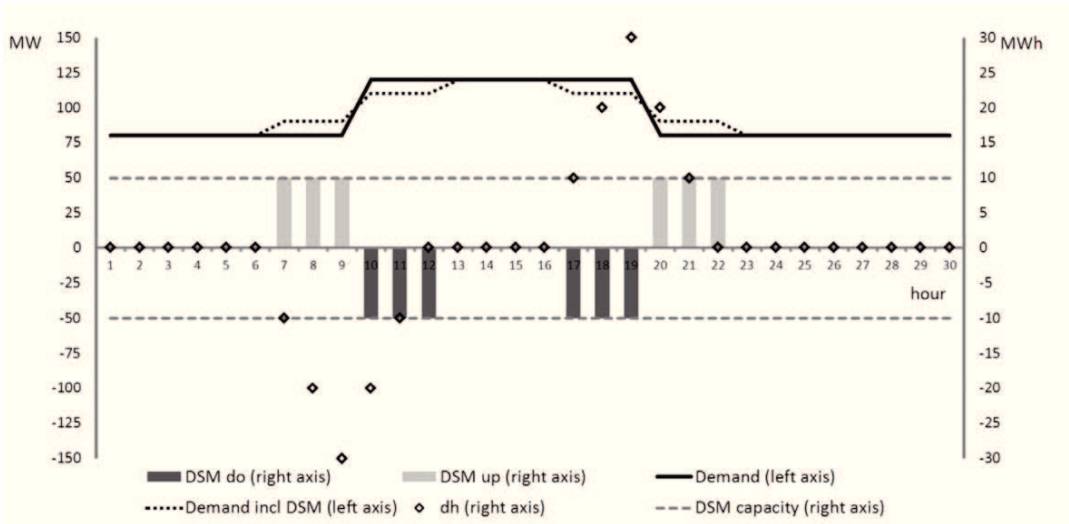
[25] The reservoir uses to be a geological cavern for underground technologies or a pressurized tank for aboveground technologies.

with financial compensations. No rebound effect is included. The curtailed capacity cannot be higher than the maximum DSM resource available such as defined in equation (52). The state equation presented in equation (53) links the recovery time (R) restrictions with the maximum consecutive periods (L_{lc}) load can be curtailed.

$$0 \leq DSM^{l}{}_{lc,t} \leq \overline{dsm}_{lc}\ \mathrm{L}_{\mathrm{t}}^{\mathrm{base}}\ (1+\delta) \qquad \forall\, t, lc \tag{52}$$

$$\sum_{tt=0}^{R-1} DSM^{l}{}_{lc,t+tt} \leq \overline{dsm}_{lc}\ \mathrm{L}_{\mathrm{t}}^{\mathrm{base}}\ (1+\delta)\ L_{lc} \qquad \forall\, t, lc \tag{53}$$

At the same time, load can also be shifted within a certain time window. This implies that a shifted load on one direction at time t should be compensated by cumulated shifts of similar size in the opposite direction over the shifting period ($\mathrm{t} - \mathrm{L}_{\mathrm{ls}}$, $\mathrm{t} + \mathrm{L}_{\mathrm{ls}}$). Similarly, every shift is constrained according to the maximum fraction of load assumed to supply this service. Equations (56) and (57) introduce these restrictions adopting the formulation presented in (Zerrahn and Schill 2015b). In this way, shifts can be done only in one direction every time.



DSM do/up: hourly shifted downward or upward; dh: demand put on hold

Figure 13. Representation of DSM for load shifting. Source: (Zerrahn and Schill 2015b)

$$DSM_{ls,t}^{up} = \sum_{tt=t-L_{ls}}^{t+L_{ls}} DSM_{ls,t,tt}^{do} \qquad \forall\, t, ls \tag{54}$$

$$DSM_{ls,t}^{up} \leq \overline{dsm}_{ls}^{up}\ \mathrm{L}_{\mathrm{t}}^{\mathrm{base}}\ (1+\delta) \qquad \forall\, t, ls \tag{55}$$

$$DSM_{ls,t}^{up} + \sum_{tt=t-L_{ls}}^{tt=t+L_{ls}} DSM_{ls,t,tt}^{do} \leq max\left(\overline{dsm}_{ls}^{up}; \overline{dsm}_{ls}^{do}\right) \mathrm{L}_{\mathrm{t}}^{\mathrm{base}} (1+\delta) \qquad \forall\, t, ls \tag{56}$$

$$DSM^{l}{}_{lc,t} + DSM_{ls,t}^{up} + \sum_{tt=t-L_{ls}}^{tt=t+L_{ls}} DSM_{ls,t,tt}^{do} \leq DSM \qquad \forall\, t, lc, ls \tag{57}$$

RENEWABLE ENERGY GOAL

The RE penetration level is presented in equation (58). The model defines the RE goal (θ_{res}) over the energy shares as the total energy produced by renewables over the total energy produced on the system. Hydroelectric generation is considered as a renewable resource and then accounted consequently. In this way, energy policies based on renewable portfolio standards (RPS) can be easily studied by assigning a desired value to θ_{res} . It simulates a goal related to the volume of VRE produced over the considered period. Even if this simulate a requirement for VRE penetration, endogenous investment on the types and extent of VRE technologies are computed to satisfy this condition at least cost. Note that setting θ_{res} to zero has the same effect to completely relaxing this constraint[26].

Additional goals assuming exogenous RE installed capacity can be also studied on the model.

$$\sum_{t} \sum_{con \neq hydro} G_{con,t}^{l} \leq \left(\frac{1-\theta_{vre}}{\theta_{vre}}\right)\left[\sum_{t}\sum_{vre} (G^{l}{}_{vre,t} - G_{vre,t}^{cu}) + \sum_{t} G^{l}{}_{hydro,t} + \sum_{t} G^{l}{}_{dre,t}\right] \tag{58}$$

BALANCING RESERVE REQUIREMENTS

Reserve sizing

The *ENTSO-E* defines three types of operating reserves (*ENTSO-E* 2013): Frequency Containment Reserves (*FCR*), Frequency Restoration Reserves (*FRR*) and Replacement

[26] This is the case where no energy policy distortion is considered into the system.

Reserves (*RR*). The *FCR* are the first containment reserve after an incident. They are automatically activated within seconds. The *FRR* are considered a secondary containment and can be automatically (*aFRR*) or manually activated (*mFRR*). They are activated based on system state information, either by an imbalance in the schedule or to recover *FCR* capacity. Finally, the *RR* are the third form of containment reserve and their function is to replace already *FCR* capacity deployed to restore system reliability capabilities to be ready for facing a new potential incident.

As far as the objective of the model is to quantify the impact of flexibility needs while capacity planning and no smaller than hourly time slice are implemented, only frequency restoration reserve (*FRR*) is considered. *ENTSO-E* code requires a probabilistic sizing of *FRR* reserves. The conventional methodology implemented by TSOs is to apply a recursive convolution method based on the statistic characterization of imbalance sources using predefined reliability levels.

Reserve requirements considered on the model concern only not-event situations. The methodology to account for them is based on the probability of system imbalances due to forecast errors of VRE generation and demand variability as detailed in (Stiphout 2017). No unit's outages were considered.

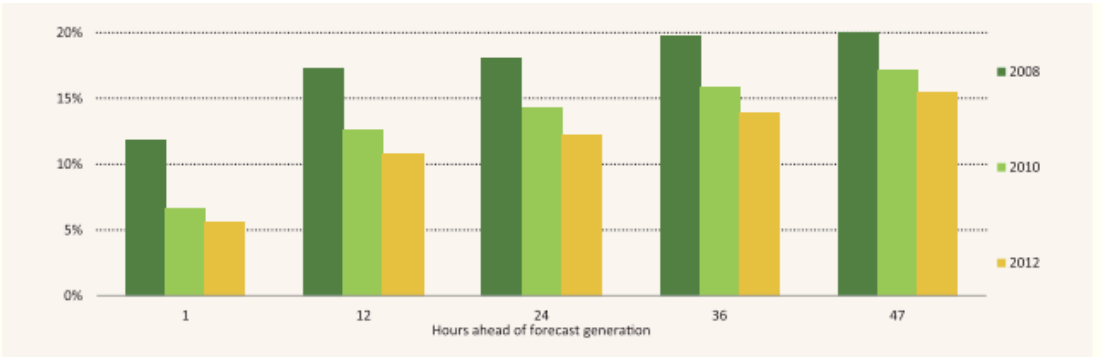


Figure 14. Mean absolute forecast error as a proportion of average actual wind generation in Spain for different leading times. Source: (International Energy Agency 2014)

Equations (59) to (62) present the reserve sizing formulas implemented in the model. The model uses a probabilistic approach for *FRR* sizing regarding load deviations and VRE forecast errors. Regarding the VRE generation, system imbalances can be decomposed on prediction error due to forecast inaccuracies and fluctuations inside the time interval considered due to resource variability.

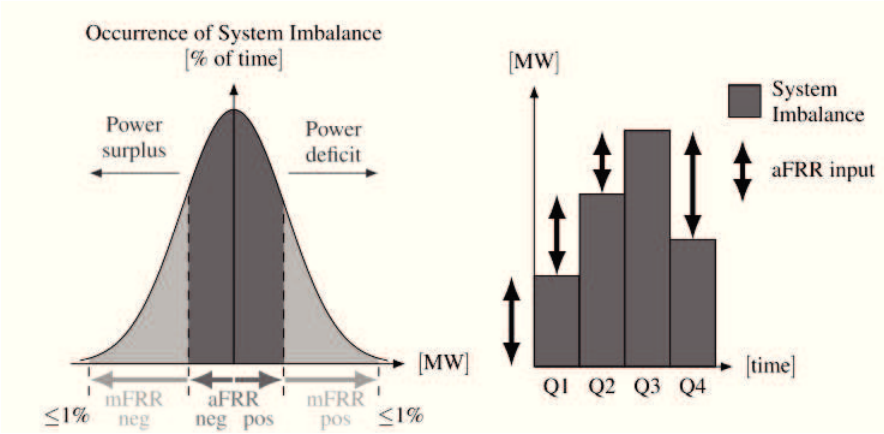


Figure 15. Static reserve sizing method. Source: (Van Stiphout, De Vos, and Deconinck 2017) from ELIA 2013.

For the purpose of capacity planning, the parameter $\varepsilon_l^{aFRR_{up/do}}$ represents the uncertainties of load and $\varepsilon_{res}^{aFRR_{up/do}}$ accounts for forecast errors driven by VRE generation. Parameters are set using historical data controlling for reliability levels of 95% and 99% for *aFRR* and *mFRR* respectively.

$$Q_t^{aFRR_{up}} = \varepsilon_l^{aFRR_{up}} L_t^{base} (1+\delta) + \sum_{vre} \varepsilon_{vre}^{aFRR_{up}} P_{vre} \qquad \forall\, t \tag{59}$$

$$Q_t^{aFRR_{do}} = \varepsilon_l^{aFRR_{do}} L_t^{base} (1+\delta) + \sum_{vre} \varepsilon_{vre}^{aFRR_{do}} P_{vre} \qquad \forall\, t \tag{60}$$

$$Q_t^{mFRR_{up}} = \varepsilon_l^{mFRR_{up}} L_t^{base} (1+\delta) + \sum_{vre} \varepsilon_{vre}^{mFRR_{up}} P_{vre} \qquad \forall\, t \tag{61}$$

$$Q_t^{mFRR_{do}} = \varepsilon_l^{mFRR_{do}} L_t^{base} (1+\delta) + \sum_{vre} \varepsilon_{vre}^{mFRR_{do}} P_{vre} \qquad \forall\, t \tag{62}$$

Accounting for reserve scheduling

Reserve requirements should be supplied by available units capable of copping with technical specifications. The balancing equations for every type of reserve are presented on

equations (63) - (66). The present formulation only considers conventional generation and storage units[27] supplying reserve.

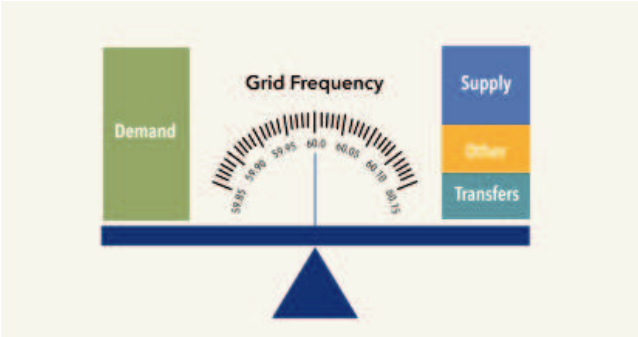


Figure 16. Balancing frequency control. Source: (Horn, Allen, and Voellmann 2017)

$$\sum_{con} G_{con,t}^{aFRR_{up}} + \sum_{ees} \left(S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{dch,aFRR_{up}} \right) = Q_t^{aFRR_{up}} \qquad \forall\, t \tag{63}$$

$$\sum_{con} G_{con,t}^{aFRR_{do}} + \sum_{ees} \left(S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{dch,aFRR_{do}} \right) = Q_t^{aFRR_{do}} \qquad \forall\, t \tag{64}$$

$$\sum_{con} \left(G_{con,t}^{mFRR_{up}^{sp}} + G_{con,t}^{mFRR_{up}^{nsp}} \right) + \sum_{ees} \left(S_{ees,t}^{ch,mFRR_{up}} + S_{ees,t}^{dch,mFRR_{up}} \right) = Q_t^{mFRR_{up}} \qquad \forall\, t \tag{65}$$

$$\sum_{con} G_{con,t}^{mFRR_{do}^{sp}} + \sum_{ees} \left(S_{ees,t}^{ch,mFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \right) = Q_t^{mFRR_{do}} \qquad \forall\, t \tag{66}$$

In this manner, synchronized power capacity of every unit is split into power generation to satisfy net load, but also reserved capacity to contribute to balancing FRR requirements.

Regarding conventional units, five types of power reserves comes up when including the two directions of automatic and manual reserves, plus the non-spinning reserve capability of fast start technologies[28]. Upward reserve supply is assumed to be on hold capacity enabling the

[27] Even if EES technologies can supply operating reserve, some power markets do not allow EES to supply balancing reserve due to regulatory issues.

[28] They correspond respectively to: $G_{con,t}^{aFRR_{up}}$, $G_{con,t}^{aFRR_{do}}$, $G_{con,t}^{mFRR_{up}^{sp}}$, $G_{con,t}^{mFRR_{do}^{sp}}$, $G_{con,t}^{mFRR_{up}^{nsp}}$

system to accommodate a sudden increase of net load, thus it deducts from the power capacity committed to the EOM balance. Downward reserve capacity is the opposite, it enables the system to defy for an unattended decrease of net load, thus, downward reserve adds to the online capacity. Spinning (*sp*) units can supply automatic and manual reserve, non-spinning (*nsp*) ones can only supply upward manual reserve. The formulation implemented in the model allows units to bid upward and downward reserves simultaneously but in a deterring way.

Based on the formulation proposed by (Van Stiphout et al. 2014), equations (67) and (68) restricts the automatic reserve supply of conventional units as a function of their generation level on time t given its automatic regulation capabilities $(\delta^{up}, \delta^{do})$. Equations (69)-(70) accounts for manual reserve constraints preventing for contracting capacity margins already used for automatic reserve supply. Reserve supply coming from non-spinning units is only possible for spare capacity of technologies with fast start capabilities.

$$G_{con,t}^{aFRR_{up}} \leq \delta^{up}\, G^{l}{}_{con,t} \qquad \forall\, con, t \tag{67}$$

$$G_{con,t}^{aFRR_{do}} \leq \delta^{do}\, G^{l}{}_{con,t} \qquad \forall\, con, t \tag{68}$$

$$G_{con,t}^{aFRR_{up}} + G_{con,t}^{mFRR_{up}^{sp}} \leq \delta^{up^{sp}}\, G^{l}{}_{con,t} \qquad \forall\, con, t \tag{69}$$

$$G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}} \leq \delta^{do^{sp}}\, G^{l}{}_{con,t} \qquad \forall\, con, t \tag{70}$$

Equation (71) describes the capacity margins of these non-synchronized units. Therefore, when accounting for reserve requirements, equation (27) should correct for the fraction of reserved capacity, as presented in equations (72) and (73). The ramping constraint is also modified to limit ramping capabilities regarding the capacity reserved on equations (74) and (75).

$$P_{con}\ \underline{\mathrm{p}}_{\mathrm{con}} \leq G_{con,t}^{mFRR_{up}^{nsp}} \leq \left(P_{con} - G_{con,t}^{l}\right) \qquad \forall\, con, t \tag{71}$$

$$G^{l}{}_{con,t} + G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}} \leq \overline{\mathrm{p_{con}}} P_{con} \qquad \forall\, con, t \tag{72}$$

$$\underline{p_{\mathrm{con}}} P_{con} \leq G^{l}{}_{con,t} - G_{con,t}^{aFRR_{up}} - G_{con,t}^{mFRR_{up}^{sp}} \qquad \forall\, con, t \tag{73}$$

$$\Delta G^{l}{}_{con,t} + G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}} \leq G_{con,t}^{+} \qquad \forall\, con, t \tag{74}$$

$$-G^{-}{}_{con,t} \leq \Delta G^{l}{}_{con,t} + G_{con,t}^{aFRR_{up}} + G_{con,t}^{mFRR_{up}^{sp}} \qquad \forall\, con, t \tag{75}$$

Similarly than for conventional units, equations (76) to (79) complete equations (38) and (39) to include reserve supply restriction. Contrary to generation units, EES units during charging are represented as loads, thus, upward reserve supply while charging means to charge slightly above the optimal level to be able to decrease system load when needed for balancing the system, which limits are expressed in (76). Downward reserve supply while charging is the opposite, charging below the optimal level to be able to increase load when needed, expressed in (77). Equations (78) and (79) represent similar constraints for EES units while discharging.

$$S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees}\, \overline{s_{ees}}^{ch} - S_{ees,t}^{ch} \qquad \forall\, t, ees \tag{76}$$

$$S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{ch,mFRR_{do}} \leq S_{ees,t}^{ch} \qquad \forall\, t, ees \tag{77}$$

$$S_{ees,t}^{dch,aFRR_{up}} + S_{ees,t}^{dch,mFRR_{up}} \leq S_{ees,t}^{dch} \qquad \forall\, t, ees \tag{78}$$

$$S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees}\, \overline{s_{ees}}^{dch} - S_{ees,t}^{dch} \qquad \forall\, t, ees \tag{79}$$

Equations (80) and (81) correct minimum charging and discharging level as previously exposed in (38) and (39) to account for reserve supply of EES units. Similar than for conventional units, ramping constraints of EES units are also further constrained by reserved capacity. Therefore, equations (82)-(85) replace equations (40)-(41).

$$S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees}\ \overline{s_{ees}}^{dch} \qquad \forall\, t, ees \tag{80}$$

$$S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees}\ \overline{s_{ees}}^{ch} \qquad \forall\, t, ees \tag{81}$$

$$\Delta S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees,t}^{ch+} \qquad \forall\, t, ees \tag{82}$$

$$-S_{ees,t}^{ch-} \leq \Delta S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{ch,mFRR_{do}} \qquad \forall\, t, ees \tag{83}$$

$$\Delta S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees,t}^{dch+} \qquad \forall\, t, ees \tag{84}$$

$$-S_{ees,t}^{dch-} \leq \Delta S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \qquad \forall\, t, ees \tag{85}$$

Adequate levels of energy should be guaranteed to supply energy and reserve simultaneously. Equations (86) and (87) control sufficient available level on storage reservoirs for units to participate on both energy and reserve markets. The parameters t_{aFRR} and t_{mFRR} are the required time durations for reserve supply required in network codes.

$$\left[S_{ees,t}^{ch}\, t_{slice} + S_{ees,t}^{ch,aFRR_{do}}\, t_{aFRR} + S_{ees,t}^{ch,mFRR_{do}}\, t_{mFRR}\right]\sqrt{\eta_{ees}} \leq E_{ees} - E^{l}{}_{ees,t} \quad \forall\, t, ees \tag{86}$$

$$\left[S_{ees,t}^{dch}\, t_{slice} + S_{ees,t}^{dch,aFRR_{up}}\, t_{aFRR} + S_{ees,t}^{dch,mFRR_{up}}\, t_{mFRR}\right]\frac{1}{\sqrt{\eta_{ees}}} \leq E^{l}{}_{ees,t} \quad \forall\, t, ees \tag{87}$$

1.5. CASE STUDY

1.5.1. DATA

A case study is presented below to test the capabilities of the DIFLEXO model for long-term capacity planning. The system has been loosely calibrated to the French power system. Time dependent parameters such as demand, water inflows of reservoirs, VRE generation profiles and day-ahead forecast errors have been obtained from the public database of the French TSO for 2014[29]. Cost and performance parameters are based on publicly available literature and presented on Table 4. Capital cost and running cost of generation technologies were taken from (IEA/NEA 2010; Schröder et al. 2013), technical parameters were taken from (Kumar et al. 2012; Schröder et al. 2013). A fixed interest rate of 7% was assumed across all the technologies considered. A baseline cost of CO_2 of 20€/ton was also supposed based on discussions with experts.

Technology	*Overnight cost*	Lifespam	*crf_i*	$o\&m^f$	$o\&m^v$	fuel_cost	CO_2 content	Load following cost
	[€/KW]	*[yr]*	*[€/KW yr]*	*[€/KW yr]*	*[€/MWh]*	*[€/MWh]*	*[t CO_2/MWh]*	*[€/MW]*
Nuclear	3217	40	241	82,1	12,3	7,8	-	55
Lignite	1601	30	129	30	6, 2	15,0	0,374	30
Hard coal	1390	30	112	30	6, 2	23,5	0,340	30
CCGT	854	30	68,8	20	2,8	54,2	0,241	20
CT	459	30	37	15	6,1	81,3	0,328	10
OCGT	757	30	61	15	6,0	54,2	0,241	15
Reservoir hydro	2953	50	214	-	1,4	-	-	8
Wind	2390	25	205	26,7	22,1	-	-	-
PV	3561	25	306	27,2	22.5	-	-	-

[29] Public data from the website of the french power system operator:

www.rte-france.com/en/eco2mix/eco2mix

Table 4. Cost assumptions of generation technologies. Sources: (IEA/NEA 2010; Schröder et al. 2013)

A portfolio of five bulk EES technologies was selected assuming the expected technology prices by 2020[30] (Kintner-Meyer et al. 2012). Among the technologies considered there are: Li-ion batteries (Li-ion), Sodium-sulfur (NaS) batteries, Vanadium redox flow batteries (VRFB), pumped-hydro storage (PHS) and adiabatic compressed air energy storage (adiabatic - CAES). Assumed cost are based on Kintner-Meyer et al. (2012) taking their 2020 estimates. Technical parameters were taken from Zerrahn and Schill (2015a) and Schröder et al. (2013).

Technology	Efficiency	Pmin	Pmax	ramp_up	ramp_down	δ^{up}	δ^{down}	δ^{sp}	m_{con}
	[%]	*[% P/min]*	*[% P/min]*	*[% P/min]*	*[% P/min]*	*[% P/min]*	*[% P/min]*	*[% P/min]*	-
Nuclear	32%	45%	100%	5%	5%	2,5%	2,5%	75%	2,303
Lig	47%	40%	100%	4%	4%	2,0%	2,0%	60%	0,269
Hard coal	47%	38%	100%	4%	6%	2,0%	3,0%	60%	1,948
CCGT	62%	33%	100%	8%	8%	4,0%	4,0%	120%	1,511
CT	34%	0%	100%	25%	25%	12,5%	12,5%	375%	2,468
OCGT	39%	20%	100%	10%	10%	5,0%	5,0%	150%	1,968
Reservoir hydro	90%	0%	100%	20%	20%	10,0%	10,0%	300%	1,111

Table 5. Technical parameters of generation units. Sources: (Kumar et al. 2012; Schröder et al. 2013)

	CAPEX -2020								OPEX -2020	
Technology	Battery	System	PCS	BOP	Lifespam	WACC	crf^E	crf^S	$o\&m^v$	$o\&m^f$
	[$/KWh]	*[$/KW]*	*[€/KWh]*	*[€/KWh]*	*[yr]*	*[%]*	*[€/KWh yr]*	*[€/KW yr]*	*[€/KWh]*	*[€/KW]*
Li-ion	510	-	150	50	10	3%	59,8	23,4	0,7	5
NaS	290	-	150	50	10	3%	34,0	23,4	0,7	5
VRFB	131	775	150	50	25	3%	7,5	56,0	1	2
PHS	10	1890	-	-	50	3%	0,4	73,5	0	7
ACAES	3	850	-	-	30	3%	0,2	43,4	0	7

[30] Only expected commercial technologies were considered.

Table 6. Cost assumptions of EES technologies. Source: "National Assessment of Energy Storage for Grid Balancing and Arbitrage" (Kintner-Meyer et al. 2012).

Technology	EES_Emin [%]	Chg_ramp [% S/min]	Dchg_ramp [% S/min]	Auth_min [h]	Auth_max [h]	Self_dch [% E/h]
Li-ion	20%	1500	1500	1	12	0,0014%
NaS	10%	1500	1500	5	10	0,0417%
VRFB	10%	3	3	2	24	0,0052%
PHS	10%	0.67	0.67	5	36	0,0521%
ACAES	15%	0.15	0.15	2	24	0,0313%

Table 7. Technical parameters of EES units. Sources: (Schröder et al. 2013; Zerrahn and Schill 2015a)

1.5.2. RESULTS

Three variations of the capacity expansion model (CEM) presented in the previous sections are implemented to investigate the impact of introducing detailed operational constraints while capacity planning. Capacity investments and economic dispatch are co-optimized using the formulations presented in the previous section. Residual load is calculated based on the load data for France subtracted by the net power exchange, the non-variable renewable energy generation (assumed exogenous) and the VRE production (endogenous) according the penetration goal under study. The market settles at marginal price for energy and FRR supply, including DSM capabilities and storage scheduling.

The first formulation tested, hereafter denoted F1, is the formulation comprising FRR balancing needs as presented in equations (63) - (85), including ramping limits, part-load efficiency losses and CO_2 emissions. The second formulation, denoted F2, includes all the equations of previous, but drops the terms accounting for FRR requirements. The third formulation studied, F3, grasps additional simplification from F2, relaxing the ramping constraints of generation and storage technologies (equations (28)-(30) and (40)-(45)) but still considers load following cost. Technical parameters and cost assumptions remain the same on the three formulations.

Formulation	Description	FRR requirements	Omitted terms
F1 – Full	LP formulation considering operational constraints and reserve requirements	Probabilistic	-
F2 – Typical	LP formulation disregarding reserve requirements	Not included	-
F3 – Simplified	Screening curve like formulation	Not included	Ramping limits: (28)-(30) & (40)-(45)

Table 8. Summary of formulations tested.

The three formulations differ on the level of detail on the representation of operating constraints. Hence, flexibility can be deployed for different purposes and can be required on different timeframes. Therefore, power generation technologies and EES can contribute for supplying FRR. EES and DSM can supply short-term flexibility for peak shaving and valley filling arbitrations from an hourly to weekly basis. Only EES capacity allows accommodating for seasonal variations and doldrums of VRE generation, as well as for guaranteeing capacity adequacy on the long-term, completing generation technologies.

On F1, the FRR requirements follows the probabilistic methodology proposed on (ENTSO-E 2013) based on day-ahead forecasting error allowing to calculate the RMSE of VREs. Statistical system imbalances are set using confidence levels of 99% and 90% to the unitary probability distribution for *mFRR* and *aFRR* dimensioning respectively (Van Stiphout et al. 2014). Therefore, when additional shares of VRE are imposed, the RMSE factors are linearly extrapolated as a function of VRE installed capacity. Minimum duration required for reserve supply of EES units was set to 0.5 h.

Imbalance source	*Hour-ahead RMSE*			
	aFRR+ [*/P_{res}]	*aFRR-* [*/P_{res}]	*mFRR+* [*/P_{res}]	*mFRR-* [*/P_{res}]
Wind	1,07%	1,28%	7,84%	2,94%
PV	0,07%	0,38%	0,37%	1,05%
*Load***	0,24%	0,56%	0,46%	0,84%

** Percentage of daily peak load

Table 9. Imbalance sources for reserve dimensioning.

All imbalances are supposed to be dealt by the TSO, who schedules FRR reserve. All players but DSM can supply power for FRR balancing. Power and reserve supply participation are restricted by the total installed capacity of technologies and their ramping, regulation and fast-start capabilities. Therefore, power dispatch and reserve requirements are co-optimized with capacity investments.

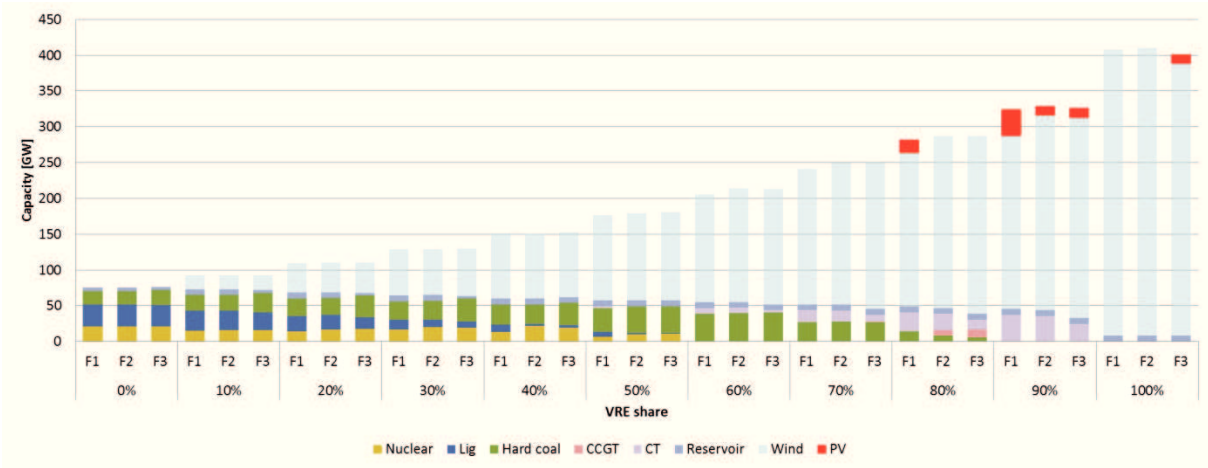


Figure 17. Optimal capacity investments on the greenfield scenario.

Under the assumptions adopted, VRE capacity is only installed when a share of RE is imposed into the system. In the case where investments on VRE are endogenously optimized without market distortions ($\theta_{res} \geq 0$), no wind or PV capacity are into the optimal portfolio. This confirms from a system perspective that investing in VRE capacity is suboptimal and causes induces additional costs.

Across all the formulations the required VRE capacity increases exponentially evidencing its very low capacity value. VRE investments are mainly composed by wind. Given that no restrictions are made to additional wind investments, PV becomes optimal and enters on the optimal investment portfolio only after wind value is sufficiently diluted due to system integration costs. Nevertheless, at 100%VRE shares, the added capacity of EES on F1 and F2 makes place for additional wind rather than PV.

Reservoir hydro capacity are competitive regardless the VRE penetration level. Furthermore, it can be seen a fuel transition from high to low fixed costs technologies (but low to high marginal cost technologies) when increasing the imposed VRE. This means that from a system perspective, VRE directly competes with baseload technologies.

It can be seen that under the CO_2 emission cost assumed, wind capacity is in competition with baseload technologies. It first shifts lignite, then nuclear and finally hard-coal capacity as can be seen in Figure 17. It can be expected that under higher CO_2 cost, the main outcome showing that VRE competes with baseload would remain, but the shifting order would change. Then, for sufficiently higher CO_2 cost, nuclear would be the last technology to be pushed-out of the optimal mix. Assuming different cost of CO_2 would have a significant impact on the marginal cost of polluting technologies which changes their relative competitiveness. The sensitivity to CO_2 cost is given by the CO_2 emission factor related to every technology. Therefore, changing the level of CO_2 cost would change the relative optimality between high and low polluting baseloads technologies, with higher CO_2 cost making the case favorable for nuclear against coal technologies. As presented on Figure 17, for an optimal setting, VRE penetration erodes the market for poorly flexible baseload technologies. VRE penetration imposes a reduction on the market volume for conventional technologies, so a volume effect appears, shrinking progressively the capacity of low capital and inflexible assets to more costly flexibility options. The way VRE capacity substitute other technologies can be interpreted as a fuel switching effect. It would depend on the relative competitiveness of conventional units, which is affected by the capabilities in terms of flexibility of different technologies combined with their cost structure.

On the three cases, investing in solar capacity is only optimal for very high VRE penetration levels (80% - 100%). This is due to the lower relative competitiveness of solar against wind capacity for the system under study[31]. The late entry of solar capacity is given by the cannibalization effect taking place over wind capacity. This is, at constant levels of flexibility, the capacity value of wind power strongly depreciates when increasing the VRE shares. Investing into solar capacity becomes optimal only when the cost of wind integration is higher than the system cost of solar.

The optimal level of capacity investments obtained are consistent between the three formulations for every VRE penetration level. Nevertheless, Figure 17 shows that the type of investments sensitively diverges for VRE shares above 20%. On F1, lignite and nuclear capacity shrink simultaneously when increasing VRE levels, while on F2 and F3 the fall is more successive. Moreover, no gas or fuel technologies are competitive when considering low to mid-shares of VRE. For mid CRE penetrations, peaking plants become optimal earlier

[31] Load, wind and solar data loosely calibrated to the case of France.

in F1 than on F2 and F3. Figure 17 shows that investing into peak and high peak technologies, which display higher marginal cost but achieve operations with higher flexibility, become economically optimal for VRE shares above 50% on F1 and above 60% on F2 and F3. This result confirms the intuition that a better representation of system operations allows to better valuate flexible capabilities of generation technologies. The previous can be furtherly proved when looking the optimal investments on flexibility options presented on Figure 18, where the total amount of flexibility investments is higher in F1, than in F2 and F3 for any VRE penetration.

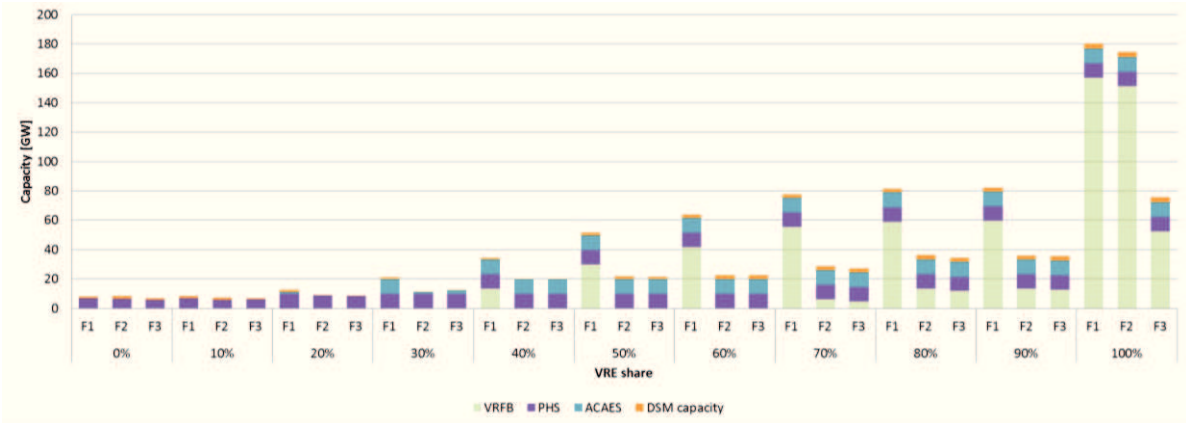


Figure 18. Optimal flexibility investments on the greenfield scenario

The three formulations show similar trends when looking at investments on flexibility options: The very low cost necessary for enabling DSM capabilities makes it competitive regardless the VRE penetration across all the formulations, but still leaving room for investments in EES technologies. The three cases opt for equivalent levels and type of investments at low VRE penetration (0-10%), where just PHS is competitive. When considering low to mid VRE penetrations levels (20-60% VRE shares), flexibility for VRE integration starts to be the main driver for investments in EES. For high VRE shares, significant investments on EES capacity are required to attain minimum system cost.

Figure 18 also shows that from 20% VRE levels the amount of optimal flexibility investments increases faster on F1 rather than on F2 and F3. Additional investments on EES technologies become optimal when VRE furtherly increases. As previously exposed, F3 only valuates flexibility for price arbitrations because no ramping constraints and no other system service are imposed on the optimization. At the same time, F2 enhances the value of flexibility by including the dynamic limits of generation units. The similar levels of investments on flexibility options at 20% until 60% VRE shares across F2 and F3 evidences that from a

system perspective, benefits coming from price arbitration and savings on ramping cost are not sufficient to justify additional EES capacity. This is explained because of the technology transition occurring on the supply-side from primarily baseload technologies to more peaking technologies. The investments on essentially flexible power generation technologies, evinced when imposing mid VRE shares, causes a substantial reduction on the market for flexibility when only balancing arbitrations and capacity adequacy are considered (F2). Gains from time arbitration alone only prompt further investments on EES capacity for VRE shares above 70%.

A more complete representation of system operations allows to better capture the value for multiservice supply, so stacking multiple value sources. Regarding flexibility options, F1 adds the value coming from system reliability by considering FRR requirements, which improves the case for new flexibility options. In F1, for VRE levels above 50%, cost-optimal EES capacity rapidly increases. Figure 18 shows the important impact that including FRR has over the optimal level of EES capacity. It shows that EES investments trigger from 10% of VRE penetration on F1 against 20% for F2 and F3. Not only the optimal level of EES capacity is higher on F1, the portfolio of optimal EES investments also diversifies faster. The difference on VRE curtailment becomes significant from 20% onwards.

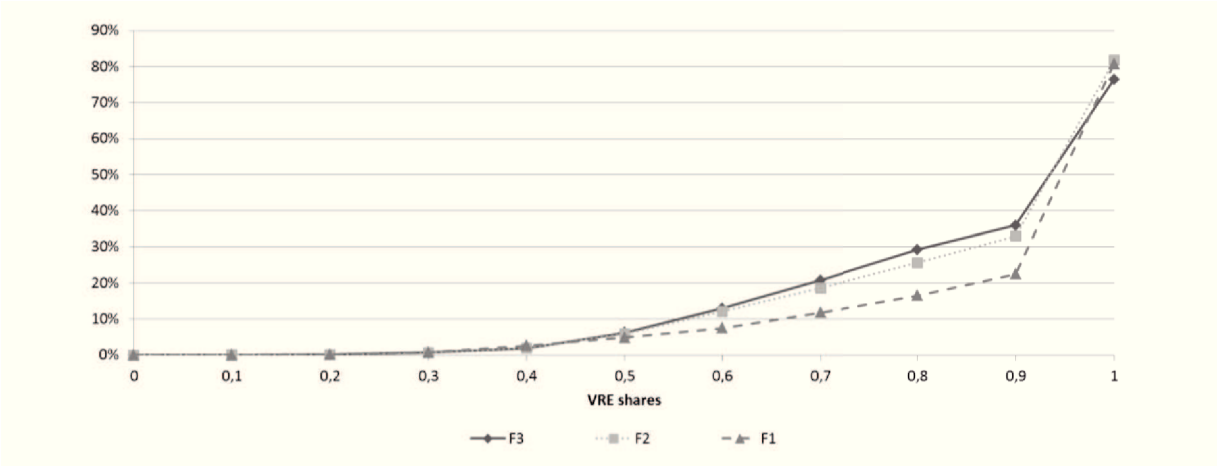


Figure 19. VRE curtailment as a percentage referred to total demand (512 TWh).

Figure 19 presents the evolution of VRE curtailment which is assumed as a free option to balance demand and supply. The results are clear: Even with important investments in flexibility options, it is cost-optimal to significantly curtail VRE for penetrations levels above 50%. For example, at 60% of VRE shares, curtailment levels are placed around 10% of total

demand. This means that in fact gross VRE generation corresponds to around 70% from which 10% is spilled.

Nevertheless, an important distinction between formulations should be made, curtailment levels can be sorted in decreasing order starting for F3 then F2 and finally F1. This is a consequence of the broadened representation of flexibility needs and the adoption of a multiservice approach on F1. The systems obtained using F1 are consequently more flexible than those using F2 and F3, which allows a better integration of VRE and therefore lower levels VRE energy spillage.

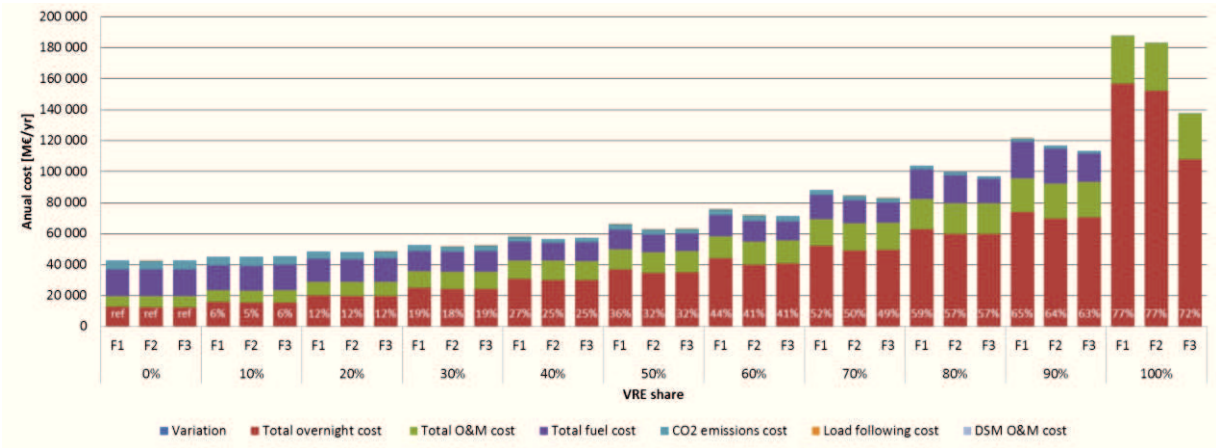


Figure 20. Total system cost.

Regarding system costs, the three formulations indicate similar trends. Total system cost rapidly rises when increasing VRE shares. This cost growth is driven mainly by the overnight cost incurred by forcing non-optimal VRE capacity to attain the RE goal imposed. This, in turn, requires adding capital intensive EES capacity for VRE integration to better accommodate the forced VRE capacity. Nevertheless, since the three formulations calculates the optimal mix for the imposed levels of VRE penetration, lower levels of EES on the mix would imply less overnight cost but even higher total cost corresponding to a suboptimal strategy. Passing from 0% to 30% VRE shares implies a cost increase of about 19% across all the formulations, while passing from 30% to 60% of VRE penetration more than doubles this increase with 44% for F1 and 41% for F2 and F3 respectively. Nevertheless, formulations F2 and F3 neglect integration cost dealing with reliability, which is better assessed on F1.

It can also be seen on Figure 20 a non-negligible increase of O&M cost across the formulations. Even if the fuel switching effect moves the optimal mix to less costly O&M cost when increasing VRE shares, there is a bigger amount of installed capacity due to the

lower capacity factor of VREs and there is more energy produced on the system that is spilled by VRE curtailment. In relation to the fuel cost, the volume effect creates a reduction on primary energy consumption but the fuel switching effect move towards the usage of more expensive fuels; both effects balance each other resulting on relatively steady fuel cost, except for the case of 100% VRE where there is only RE generation and pure flexibility options on the system.

Similarly, CO_2 cost diminishes progressively while increasing VRE shares due to the global reduction of CO_2 emissions. More flexible generation capacity, obtained due to the fuel switching effect, better contribute to VRE integration. Given that the CO_2 content of gas is lower than that of lignite or coal, the net effect of a fuel transition from coal to gas is a reduction of system's emissions. Nonetheless, at constant energy generation levels, replacing nuclear for hydrocarbon based technologies makes the system to increase the CO_2 emissions. This interpretation is presented on Figure 21.

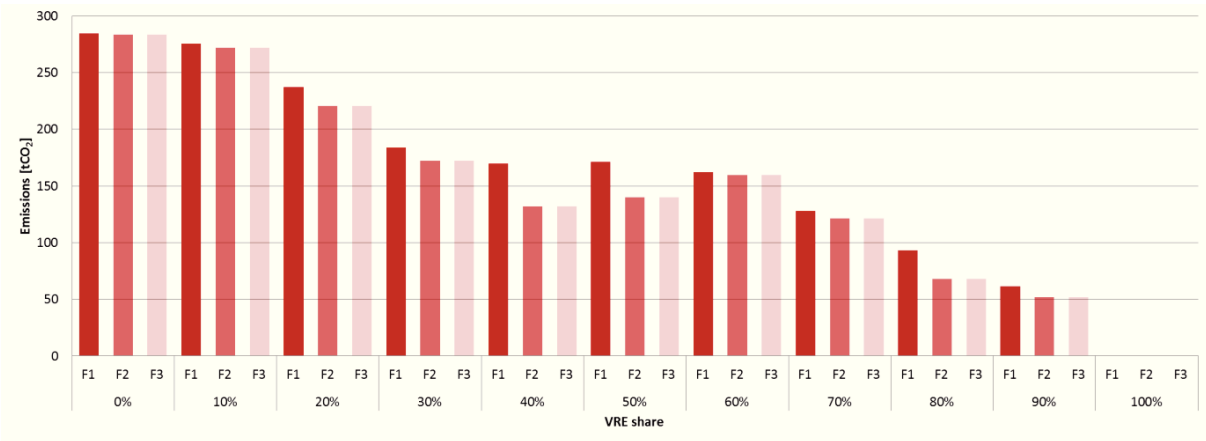


Figure 21. CO_2 emissions on the Greenfield optimizations.

To understand the trend of CO_2 emissions, the competition between VRE capacity and baseloads technologies should be depicted. On the three formulations, it is confirmed that at low VRE shares, lignite capacity is the first baseload technology to be replaced by VRE capacity. The result is an important reduction on the CO_2 emissions. At mid VRE shares, the lignite capacity continues to be pushed-out of the optimal mix and the replacement of nuclear capacity follows. There is an initial reduction of total CO_2 emissions from 20% to 40% VRE shares followed by a rebound from 40% to 60%, resulting on a "U" shaped CO_2 emissions curve. This trend is explained by the volume and fuel switching effects acting in the same direction at low to mid VRE penetration and then in the opposite direction from 40% to 60%. This effect is slightly mitigated on F1 because of a better estimation of system

flexibility for VRE integration. From 60% VRE penetration and above, VRE generation becomes the main baseload technology triggering investments on flexible capacity and flexibility options to facilitate its integration, which prompts the replacement of the remaining hard coal capacity, occasioning a net decline on the CO_2 emissions. It can also be seen that formulations F2 and F3 tends to under estimate CO_2 emissions when compared to F1.

1.6. DISCUSSION

The model presented in this paper is a capacity expansion model in which energy supply and reserve requirements can be co-optimized considering a large set of operational constraints representing system operations. This framework is well suited to evaluate investments in capacity and flexibility resources simultaneously; hence, it is in line with a resource-adequacy (RA) method in which the balance between demand and supply is also studied during challenging ramping conditions and where there is little conventional capacity scheduled due to ambitious renewable energy penetration levels progressively forced into the system.

The current formulation assumes a system under perfect competition and perfect foresight. Real markets are far from being deterministic and predicable, market players can also interact in some degree. Attention should be payed when analyzing the value of flexibility resources under deterministic frameworks. Bidding strategies of pure flexibility options are based on tradeoffs between real-time markets and the expectations of price evolutions, which is predominantly a stochastic problem. Thus, the results obtained using these ideal assumptions set an upper bound on the operations of EES.

Furthermore, the formulation here presented leaves aside the power network. No interconnections or grid constraint is considered. This simplification can overestimate the flexibility needs of the system for the services considered. Nevertheless, the inclusion of further details on the dynamics of the power system, such as supplementary ancillary services, locational signals for congestions management, network investment deferral, among others, would open additional sources of valuating flexibility options on the system, and would compensate the inaccuracies introduced by the idealistic assumptions considered.

1.7. CONCLUSIONS

The lack of representation of system needs, including operational and reliability information, may result on suboptimal capacity investments when variability enters into the system. This makes necessary to reformulate traditional capacity expansion models (CEM) as a resource-adequacy problem in which a broader representation of system requirements is implemented, allowing to capture the value of different system services. Additionally, an accurate representation of technology capabilities is also required to cope with the power demand, and to manage the wider system services required for VRE integration. Nevertheless, trade-offs should be present when introducing detailed operational constraints into investment models. The dimensionality of the solving problem grows dramatically, and computation time becomes constraining when refining the complexity of power system dynamics.

Being aware of these modeling challenges, this chapter focuses on the development and illustration of the capacity expansion model DIFLEXO. It uses stylized formulations to shed light on the impact of representing operating constraints while endogenously optimizing capacity and flexibility investments. Hence, the contribution of this chapter is twofold: first, endogenous investments in flexibility options are incorporated into a linear dispatch-investment tool, in which, EES and DSM capabilities are co-optimized with conventional and VRE capacity investments to balance different system's needs. Second, the integration of reliability criterions on power system planning is supposed to claim increasing importance at significant VRE penetration levels because of the increasing forecasting errors impacting the residual load. Therefore, the conventional representation of the power system is enlarged by the introduction of FRR requirements for capacity expansion.

In order to assess the impact of operating constraints over the optimal investments, three formulations were compared (F1, F2 and F3). They were tested by using the same system cost definitions but assuming varying the level of detail on the representation of system constraints and system's needs. Results show that for VRE shares between 0-20%, there is almost any difference between the optimal capacities across the three formulations: optimal capacity level and technology type are very close; the same is valid for system cost and resulting CO_2 emissions. Only flexibility for power adequacy and for optimal operation of conventional units is valuated. Thus, little amounts of PHS capacity is required because power generation units sufficiently supply power and system flexibility.

Nevertheless, after 30% of VRE penetration, higher flexibility for optimal VRE integration becomes imperative. Therefore, it is confirmed that an inaccurate representation of operational constraints may drive highly suboptimal investments, or even, to infeasible power mix. Investments on flexibility options rise earlier and faster when a more complete representation of system dynamics is adopted. When a broader representation of power system requirements is implemented, flexibility options prove to add significant value to the system. These results confirm the belief that, under the cost levels expected by 2020, EES and DSM technologies have a major role to play when considering significant shares of VRE.

It can be seen on the most complete formulation (F1) that new capacity of flexibility options increases exponentially between 30% and 60% VRE penetration levels, in this range, its value is high because of the complementarities originated when less flexible generation technologies compose the system. From 70% to 90% of VRE shares, peak and extreme peak investments enter the optimal mix making flexibility options to compete with capabilities from more flexible generation technologies. This competition results on a stagnation on the optimal investments on EES and DSM. At 100% of VRE penetration, investments on flexibility options uptakes its exponential grow pattern because of the tight technical restriction imposed by no allowing at all generation from conventional technologies, even for extreme episodes.

It was also confirmed that a misrepresentation of operational constraints neglects system cost associated with VRE integration. This cost deviation corresponds to both, an underestimation of additional investments in flexibility options and the intensification of operating cost to accommodate more a fluctuating residual demand. Associated CO_2 emissions are also underrated due to the mistreated contribution of conventional units for VRE integration given the important cost of investing in flexibility options. Energy spillage in form of VRE curtailment is lower on formulations with higher detail on system operations because they better capture the system value of flexibility, then, the resulting mix is more flexible and appropriate for VRE integration. These results not only show the importance of enlarging the problem formulation to include additional system services for capacity optimization on scenarios of important VRE shares, but also highlight the necessity to simultaneously include generation and flexibility options into the investment portfolio. That is, adopting a system perspective with multiservice approach.

In summary, the notion of flexibility has been analyzed and interpreted as a service with multiple delivery timeframes, serving different purposes and being supplied by multiple technologies. Alternative model formulations were compared while increasing shares of VRE. The results confirm the postulates evocated in the literature. The DIFLEXO model also allows to study power investments on brownfield scenarios and to conduct sensibility analysis over relevant energy policy issues. The model can furtherly be improved to include cross-border exchange as an additional source of flexibility. These subjects constitute the topic of further research.

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CHAPTER II

THE VALUE OF ELECTRIC ENERGY STORAGE AND ITS WELFARE EFFECTS:

THE CASE OF FRANCE

CONTENTS OF CHAPTER II

2.1. INTRODUCTION

Apart from the limited and very site specific hydroelectric resources, the dominant emerging renewable energy technologies are wind and photovoltaic. They are considered as variable renewable energies sources (VRE) because of their inherent nature. The significant technical progress they have achieved during the last decade together with the important cost reductions have made them be at the core of the claim for a clean energy future. Yet, they are non-dispatchable, their low capacity factors, as well as the difficulties for their predictability, establish new operational and regulatory challenges, particularly when important shares are expected to be deployed on current power systems.

The increasing VRE penetration not only reveals often ignored questions dealing with system services and reliability, which are services that have been supplied with little effort, and sometimes, even inadvertently by conventional units on a centralized electricity scheme (e.g., voltage stability, frequency regulation, and inertia support), but variable generation also stresses key market inefficiencies both in the long and in the short-term. Recurrent negative electricity prices and exacerbated price volatility on electricity markets are evidence of some of the challenges that are experiencing current market architectures due to the unplanned and sometimes "forced" advent of VREs. Those issues point to the awareness supporting that: physical interactions of VRE supply on today's power systems, market integration policies of VRE for supporting such technologies without hindering the short-term and long-term coordination of market players, and the regulatory reforms required for enabling the supply of multiple services needed for improving system responsiveness to variability are still poorly understood.

The ability to store electricity and/or shift demand during periods where there is an excess of VRE generation to transfer it towards periods where such energy is more needed, hence valuable; on which conventional technologies exhibit high ramping cost or tight load following constraints, can provide substantial value to the system (Black and Strbac 2007; Carnegie et al. 2013; Connolly et al. 2012; Denholm et al. 2013; Fitzgerald et al. 2015; Van Stiphout, Vos, and Deconinck 2015). Additionally, electric energy storage (EES) can induce investment deferrals on the generation and grid assets by providing firm capacity, reduce CO_2 emission under the right market conditions (Carson and Novan 2013; de Sisternes, Jenkins, and Botterud 2016), and alleviate adequacy and reliability issues. Nevertheless, emerging flexibility technologies, such as EES and demand side management (DSM), are completely disregarded on the official clean energy agendas and power sector roadmaps on

most countries[32], or are oversimplified under the ambiguous employment of the notion of "smart grids"[33].

Some EES technologies have already proved market readiness (Berrada, Loudiyi, and Zorkani 2016; KU Leuven Energy Institute 2014; Luo et al. 2015; Mahlia et al. 2014; Palizban and Kauhaniemi 2016). Despite their still high investment cost, they can efficiently supply multiple services to the system at very low short-run marginal cost. Nevertheless, the decision makers still perceive them as not mature enough and costly. This is mainly due to the fact that their benefits use to be hidden behind regulatory veils[34], and their value uses to be sparse. As a consequence, they are completely absent on official electricity roadmaps.

Understanding the importance of flexibility options on a market framework and acknowledging for welfare effects is not a new topic. There is an extensive literature related to the theory of commodity prices and storage developed in the field of agricultural economics starting with the seminal papers of Working (1949) and Gustafson (1958). Thereafter, the understanding of storage economics further developed during the 60's and 70's with the analytical studies on inventories and price stabilization by Brennan(1958), Helmberger and Weaver (1977), and Newbery and Stiglitz (1979). They extended the works of Working and founded a complete theory on commodity price stabilization. In (David M. G. Newbery and Stiglitz 1982) and (Wright and Williams 1984), short and long-term welfare effects are studied analytically broadening the assumptions to account for risk aversion under random commodity prices, suppressing the hypothesis of costless stabilization[35] and considering that there is not a complete set of insurance markets[36]. In (Blake and Johnson 1979) a basic inventory problem is compared in detail against an equilibrium problem that represents the intertemporal price arbitration of a commodity in a competitive market. This paper establishes the linkages between the analytical studies previously done on firm inventories and price stabilization with the empirical models using competitive equilibrium

[32] Exceptions at state level exist in the US. In California, Legislation (AB 2514) enacted in September 2010 for the adoption of requirements for utilities to procure energy storage systems. This Assembly Bill instructs the California Public Utilities Commission (CPUC) to stablish EES targets for each of the three IOUs. The CPUC required on 2014 the utilities to collectively procure 1,325 MW of energy storage by 2020.

[33] A detailed description and assessment of the smart grid solutions is presented in chapter IV.

[34] High value sources may appertain to the regulated sector.

[35] This would be equivalent to costless storage.

[36] This is equivalent to considering there is no perfect price stabilization due to storage capital costs.

frameworks. From this point, it is possible to apprehend the findings achieved by the analytical literature on inventory and price stabilization applied to agricultural commodities, to extend them to the analysis of other commodities, specifically to the study of electricity markets, since they can also be represented as partial equilibrium problems. Therefore, the analysis of power systems with electricity storage can be outlined using the framework established by the theory of commodity prices.

However, the theoretical case for current electricity markets includes further problem dimensions than that considered in the seminal analyses of commodity prices. Some of them are: there is no longer one producer but a collection of them that can be classified by their short-run marginal cost[37]; on the demand-side, demand is represented as inelastic, nevertheless, some demand flexibility can be enabled allowing real time load shifting and load shedding; there is not just one market to be balanced but multiple services over different locations and delivery times. All those aspects should be taken into account; Furthermore, enabling energy storage capabilities implies non-negligible capital allocation and VRE adds higher frequency imbalance probability than the case of agricultural commodities.

Assessing the relevance of flexibility on current power systems is a challenging question that is closely related to the methodology and the system representation assumed. The complete value of flexibility technologies, but also that of conventional and renewables, should be apprehended from a system perspective taking into account the full interactions between generation technologies, likewise the direct and indirect costs they involve (i.e., investment and O&M cost, but also related CO_2 emissions, grid integration and profile costs). This suggests that conceiving the power systems of the future is not only a matter of costs but of value.

In view of that, Joskow (2011) points out the flaws of using cost-based average metrics[38] to compare the value of generation technologies of different nature. A distinction should be made between dispatchable and intermittent electricity generation technologies. He insists for embracing more integrated frameworks for assessing the value that every technology will add to the system rather than compare cost-based metrics. In (Keppler and Cometto 2012)

[37] Which result on the merit order stack.

[38] Metrics like the levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) use to oversight the system state and its capability to integrate the specific technology under study.

the authors explore the issue by arguing that VRE generate externalities that are traduced into supplementary costs "over and above plant-level" boundaries. They, thus, adopt a system level perspective to broad the comparison of the value of VRE against dispatchable technologies, with a particular focus on nuclear energy. In this framework, they explain the main nature of VRE externalities by using the two categories introduced by Scitovsky[39]: first, VRE induces technical externalities when introducing supply variability, these externalities are asymmetric relationships between the market players, "in which the affected parties have no means of responding" to the producers of them, thus, some kind of public intervention can be justified in order to alleviate the loss of well-being generated; and second, VRE induces pecuniary externalities while clearing the market with priority due to its very low short-run marginal costs, these externalities "operates through the price mechanism" and therefore are, in theory, inertly regulated by the market, therefore, "doesn't constitute a suboptimal situation" for overall welfare. The report of (Keppler and Cometto 2012) builds the foundations over which any policy oriented study of power systems with significant shares of VRE should be founded.

By way of further developing their findings, what has been emphasized in (Joskow 2011) and in (Keppler and Cometto 2012) is the need for closing the gap between cost-based approaches, which deals with technical aspects of technologies at plant level but without considering the rest of the power system, and system-based approaches[40], which represents the power system as competitive markets towards the equilibrium but without giving sufficient detail to the operational characteristics of plants and their interactions.

Adopting the economic theory of market equilibrium to analyze the current concerns of power systems, particularly those that have been revealed and exacerbated with the advent of VREs, is essential in order to deliver a fair estimation of the value of technologies. In this sense, electricity needs to be conceived as an energy carrier but also as a commodity. This is a prerequisite to assign it the main attribute of any real world economic good which is heterogeneity. From an economic point of view, the "heterogeneity of electric energy" claims for the variations on its marginal value associated with the network location, time and steadiness of supply that should be guaranteed for electricity to be "usable". Each one of

[39] Scitovsky, 1954. Two concepts of external economies. J. Polit. Econ. 62, 143–151. doi:10.1086/257498

[40] In this sense, "economic approach" makes reference to the implementation of economic theory to make explicit the value of assets (i.e., power capacity) and products (i.e., energy and other services).

these factors should be conceived as a dimension of the problem that needs to be balanced by the markets. In (Hirth, Ueckerdt, and Edenhofer 2016) this issue is exposed in a very instructive way: physically, "technologies produce the same physical output (MWh of electricity)", but "economically, they produce different goods". The key figure reflected by Hirth is good's "substitutability"; it means that a megawatt-hour of electricity is only imperfectly substitutable along different moments, locations and system's states. On the supply side, generation technologies should be apprehended as producers balancing the different dimensions of this asset subject to their own dynamic capabilities[41]. Therefore, each service to be balanced corresponds to a dimension of a heterogeneous problem. In this way, the whole interactions between system needs, supply assets, and their related costs can be properly analyzed.

The contributions of the present chapter are the following: studying the conditions under which enabling new flexibility capabilities may prove to be the cost-optimal investment option for the French power system over different horizons relevant to the current energy debate; analyzing to what extent should they be developed while considering balancing of multiple services; and assessing the welfare variations of stakeholder's as a product of different capital allocations and changing dispatch decisions. This paper is organized as follows: Section 2.2 presents a survey of studies dealing with the role of new flexibility technologies and discusses the relevant issues to be attempted. Section 2.3 characterizes the sense of benefits and value of flexibility technologies under study, sets the necessary boundaries of the quantitative assessment and explains the procedure proposed. Section 2.4 exposes the case study based on the French official renewable portfolio standard (RPS) adopted for the 2020 and 2030 horizons. A portfolio of bulk storage technologies is studied by considering a least-cost optimization problem where the existing electricity mix is that of 2015 (i.e., a brownfield optimization) and allows for endogenous capacity expansion and/or contraction (investments and mothballing decisions) subject to typical operational constraints. In this way, the system value of EES technologies is quantified in the case they prove optimality. Surplus variations across producers are addressed and welfare effects are discussed. The final section concludes by highlighting the main findings and developing the energy policy implications.

[41] Their own technical limits and their related costs.

2.2. ASSESSING POWER TECHNOLOGIES: CAPABILITIES, COSTS, AND VALUE

Assessing the value of generation and flexibility technologies involves quantifying its interactions with the rest of the system. It also relates using the available resources and including the energy policies in place. Therefore, adopting a system perspective framework is a requisite for technology valuation. Such valuation frameworks are defined as integrated or whole assessment frameworks in which long-term choices (capital stock allocation) are coupled with midterm decisions (optimal economic dispatch, maintenance decisions, and inventory optimization) and real time dynamics (stability of supply and system reliability), over the whole interconnected system. Yet, those models use to be complex multi dimensional equilibrium problems that are affected by the curse of dimensionality. Simplifications use to be implemented on a case by case basis constituting a trade-off exercise.

There exists an extensive literature on the subject of storage technologies for power system applications. A branch of this literature gives a technology comparison, describing the main characteristics of each technology and its potential applications (Evans, Strezov, and Evans 2012; Eyer and Corey 2010; Gyuk et al. 2013; Koohi-Kamali et al. 2013; Luo et al. 2015; Rubia et al. 2015; Yekini Suberu, Wazir Mustafa, and Bashir 2014; Zhao et al. 2014). They introduce the capabilities of EES technology, bulk or distributed, and the benefits they may supply to the system, comments on the development challenges use to be also briefly commented. Some publications focus on the assessment of business cases of particular EES facilities on specific markets. In this literature, the hypothesis of "small-scale storage" is broadly adopted because the motivation uses to be centered on studying the feasibility of an EES facility from a project finance view. This infers an important simplification, it is to assume EES to be a price-taker player, thus, ignoring profit cannibalization effects (Denholm and Sioshansi 2009; Ekman and Jensen 2010; Figueiredo, Flynn, and Cabral 2006); Most of the time, only one technology and no a portfolio of technologies are studied using representative weeks (Connolly et al. 2012; Sigrist, Lobato, and Rouco 2013; Walawalkar, Apt, and Mancini 2007), hindering to extrapolate results obtained for this particular technologies to others with different technical characteristics and maturity states. Moreover, different services use to be considered but evaluated in isolation[42] (Butler, Iannucci, and Eyer 2003; Denholm et al. 2013; Sioshansi et al. 2009; Walawalkar, Apt, and Mancini 2007).

[42] Namely: energy arbitrage, resource adequacy or reserve supply

Furthermore, there is relevant subject related to cost-effectiveness as opposed to cost-optimality when assessing the value of storage. Cost-effectiveness (Eyer and Corey 2010; Kaun 2013) implies adopting a merchant perspective where the monetizable potential of storage is limited to the boundaries of the owner of the storage facility. Cost-optimal storage valuation adopts a system wide perspective where capacity and dispatch are jointly optimized and technology specific externalities can be tacked into account (e.g., profit cannibalization effect due to price stabilization).

In (Black et al., 2005) a parametric analysis of the value of storage is presented for the UK using a partial equilibrium model. Energy and reserve supply are optimized considering different levels of VRE penetration. It is showed how the value of storage increases over that of peaking units for high wind penetrations. In (Lamont 2013), it is stated that changing the capacity of one technology, including storage, may change the marginal value of the remaining ones because every power mix has an optimal economic dispatch related to the supply curve and the expected load. This is a key issue regarding the valuation of any technology in a market context. Hence, only by simultaneously optimizing capacity investments and dispatch decisions, the condition for cost-optimal capacity deployment may be undeniably satisfied. This is, for every technology in the system, equalizing the marginal value of capacity with its marginal cost at the equilibrium (Stoft 2002). Lamont also recognizes this when claiming that "finding an overall optimum is challenging" and can become even more complicated when multiple services are to be satisfied. The author develops an analytical optimization model to evaluate each value component of storage on price arbitration. The model is transformed into Lagrangian equations and the corresponding multipliers are obtained. He identifies two factors relating the marginal value of each of the EES components considered[43]. He outlines a "self-effect", manifested by a decrease in the marginal value of a component due to the increase in its own capacity, and a "cross-effect", where the marginal value of a component decreases as a result of the increase of other's capacity. This is explained by the impact that a marginal variation in the capacity of components would have over the merit order, modifying the electricity price, which will cause a change in the optimal inventory decisions of EES, affecting, in turn, its optimal dimensioning as wells as the that of the other technologies. This kind of sensitivities of components on the value of storage can only be captured by a co-optimization approach.

[43] Namely power capacity and energy capacity

At the beginning of the decade, there was a rise in interest for electricity storage as a potential solution to alleviate issues of price volatility of gas and electricity (Figueiredo, Flynn, and Cabral 2006; Sioshansi et al. 2009). In (Sioshansi et al. 2009), the authors present the economic principles of storage for price-arbitration on the PJM market. Using a parametric study they explore the influence of efficiency and energy capacity (storage dimensioning) of storage to capture revenues on the energy only market. They find that 1GW with 4h of storage for price-arbitration gathers 50% of maximum revenues; 8h and 20h would get 85% and 95% respectively. These findings evidence the fact that additional storage provides little incremental arbitrage opportunity[44]. The authors abstract from including cost on their analysis, nevertheless, they are aware that the marginal cost of increasing an hour of stored energy can widely vary the cost structure of facilities. They highlight that: *"There is no universal optimal size of storage because it will depend on the technology and planned applications"*. They identify a multiplier effect between an efficiency increases over the arbitration revenues, which is explained by an interaction between price and quantities: a more efficient technology would not only need to charge during fewer hours to restitute the stock (quantity effect) but also would do it during the less expensive ones (price effect). Therefore, the value of storage is technology specific[45], depends on the optimal sizing of the reservoir and the power conversion system (PCS) and is related to the applications/services considered[46]. Any unambiguous valuation of storage should consider the latter.

The results in (Go, Munoz, and Watson 2016) suggest the value of storage to be widely influenced by the assessment framework. They compare the system value of storage obtained from a sequential optimization where generation-and-transmission-expansion are obtained in the first step, and storage is added in a second step, against the value resulting from the fully co-optimized ESS model they propose. They use a MILP formulation that co-optimizes investments in generation, transmission, and bulk ESS, as well as dispatch decisions subject to RPS constraints. No operational constraints are considered and the optimization is done over five representative days to assure numerical tractability. Even if the system value of storage increases with the RPS level required in both cases, they observe

[44] The latter describe EES for price-arbitration as a production factor following the law of diminishing returns.

[45] Technology type defines the round-trip efficiency and costs (fixed and variable).

[46] Locational issues are also quite relevant on EES valuation. Network bottlenecks and congestion alleviation can add up to 38% premium to the arbitration value of storage (Sioshansi et al. 2009).

that the sequential optimization method captures at most 1.7% of the savings over the total system costs induced by storage on the co-optimization framework. Introducing co-optimized ESS improves energy balancing across the network, lowering integrations cost of VREs and reducing renewable curtailment. However, the main value source of storage under their co-optimization framework is given by the induced investment deferrals, which in economic terms correspond to capital stock substitutions.

The importance of considering a broader representation of system needs on system expansion models with new flexibility options is presented in (Villavicencio 2017). A co-optimization model of generation and storage capacities are tested under three formulations diverging on the detail of dynamic constraints with increasing VRE shares. On the three formulations studied, higher investments in storage become cost-optimal when increasing VRE penetration levels. Nevertheless, greater amounts of EES investments are obtained on the model with the full representation of operational and reliability constraints, proving that disregarding such operational requirements while capacity planning would drive to sub-optimal power mixes and non-estimated overruns.

In (Berrada, Loudiyi, and Zorkani 2016) the economics of storage are studied considering the revenues coming from both arbitration and regulation within different markets. They find that cumulating revenues on multi service supply allows EES units to show a high probability of generating positive net present value (NPV). Other benefits of storage are also acknowledged broadening its potential value sources.

The business case of storage is particularly affected by its own inner presence because of its price stabilization effect. (Denholm et al., 2013a) point out the precise challenge faced by storage on a system perspective: while charging, storage is considered as an added demand which causes an increase in the market price during off-peak period; but when discharging, storage acts as a generator, decreasing the price during peak periods. This effect reduces or, in the extreme case, eliminates the profits of storage, even while continuing to provide benefits to the system and consumers. The issue highlighted here by Denholm et al (2013) suggests that system-optimized storage facilities may induce external benefits to the power systems, leading to well-known subjects of Welfare Economics dealing with the governance of public goods, externalities and information asymmetries.

In (Pudjianto et al. 2013) it is stated that the main elements that need to be considered when analyzing the system value of storage are: simulating over broad time horizons and using

different asset representations. This is mainly because storage induces savings in operating costs but also can be complementary with generation and network assets, making investment deferrals and capital savings. This is particularly important when system requirements are tightly constrained, as it is the case for systems with significant shares of variable generation. Storage and DSM can also support congestion management on the T&D network, enabling savings on re-dispatch costs and investment deferrals.

In (Strbac et al., 2012) and (Pudjianto et al., 2013) whole-system assessment models are implemented to assess the value of adding generic electricity storage to the UK power system. In this way, their models optimize investments in generation, network and storage capacities while considering reserve and security requirements. Their generic, or "technology-agnostic", approach about storage seeks to represent a different type of bulk and distributed EES technologies by testing possible ranges of cost and technical parameters. Both studies found the value of storage to be "split" across different sources coming from different segments of the industry. In (Strbac et al., 2012), the value of storage is assessed on 2020, 2030 and 2050 horizons. They find that the EES value significantly increases with the contribution of renewables. But they also recognize that even in the scenarios dominated by nuclear energy, storage has a role to play. When stacking the value sources on the reference case considered, the system savings produced by storage increase from £0.12 bn per year in 2020, to £2 bn in 2030, up to £10bn per year in 2050. Enhanced forecasting techniques, flexible generation, interconnections, and DSM are found to reduce the value of EES. They also distinguish that a portfolio of EES technologies, rather than just one technology, would likely be required to supply the range of applications required at least cost, but they don't recognize which. Meanwhile, (Pudjianto et al., 2013) concentrates on the 2030 horizon, where wind share is estimated at 52.2%, focusing on the future cost uncertainty of storage technologies. They spread over wider detail on the parameters used for quantifying the value of storage related to its capital costs. They find that the cumulated value of EES goes from £0.1 bn to £2 bn per year when considering annualized investment cost ranging from 500£/kW per year to 50£/kW per year, for bulk and distributed EES.

In (Schill, 2013), a similar investment model including storage is proposed to study the role of storage on the German power system. Nevertheless, the model implements a rather stylized hourly dispatch where all thermal generators and storage are assumed to be perfectly flexible. Aggregated must-run levels are assigned to conventional technologies looking to reflect a combination of economic, technical, system-related and institutional

factors to be met. Three storage technologies are considered using a fixed energy-power ratio linking investments into power capacity for charging or discharging (in MW) and energy capacity (in MWh). The official German energy and climate targets to 2022 and 2032 horizons are analyzed as the reference cases, where VRE capacity is expected to triple from 2010 to 2032. A long-term scenario to 2050 is also considered assuming the official renewable share of 86% of the total power consumption and the complete phase-out of lignite. Nevertheless, demand is assumed to be lower than that of 2032 due to important energy efficiency efforts. The initial PHS power and energy capacities are 6.3GW and 44GWh corresponding to the existing levels of 2010, and it can be extended until 9 GW. Hydropower is constituted essentially by run-of-river with 4.5 to 4.9 GW and generates at constant levels. On this setting, he finds that storage investments are only triggered on the cases where VRE curtailment is constrained to at least 1%. Must-run levels considered have a high impact on the magnitude of triggered investments in storage. On average on the 2022 horizon, feasible storage investments vary from zero to 9GW in 2022 and from 2 to 22GW in 2032 when VRE curtailment is constrained to 1% and 0.1% respectively and no must-run constraints are included.

In (Artelys et al., 2013), a study in a similar direction is presented for the case of France on the 2030 horizon. Nevertheless, the electricity mix considered is based on the capacities provided by public scenarios, so investments in conventional technologies are fixed. No investment in storage is necessary. This results should be taken with care because the scenarios adopted have been defined without considering system services needs, therefore the value of flexibility technologies is incompletely assessed and storage investments present limited feasibility.

The case of Texas on the 2035 horizon is studied in (de Sisternes et al., 2016). A capacity expansion model is implemented considering unit commitment constraints, reserve requirements and mass-based CO_2 limits representing total CO_2 emission caps. Two generic EES technologies are represented with fixed E/P ratios with exogenously-specified installed capacities varying in reasonable ranges. The parameters of the EES technologies considered are loosely calibrated to represent a Li-Ion kind unit and a PHS kind unit with 2:1 and 10:1 energy to power ratio respectively. Minimum and maximum capital cost levels are assumed to represent the cost uncertainty of EES technologies. The experimental setup contains 35 cases obtained by combining a set of seven EES levels and five scenarios of CO_2 emission limits. An additional scenario is included to represent a situation with restrictive CO_2

emissions (100 t/GWh) with no nuclear eligibility. The power system is modeled with hourly resolution but only four representative weeks are simulated in order to control dimensionality and keeping the problem tractable. The results show that even if EES technologies reduce average generation cost in all the cases regardless its capital cost, the total system savings induced are only positive in the case where lower bound capital cost is assumed for the "PHS-kind" unit. The savings induced by the "Li-Ion kind" unit are neutral at best. In the case where VRE are the only alternative to attain the CO_2 limits imposed, it is found that storage has an important role to play and its presence reduce total system costs for both technologies. PHS kind unit is feasible even for upper bound capital costs assumed. These findings coincide with the previously exposed in (Go, Munoz, and Watson 2016; Villavicencio 2017) where the value of storage increase with the VRE penetration.

Recent studies have also investigated the impact of electricity storage on social welfare. (Grünewald 2011; Sioshansi 2010, 2014) have included storage capabilities on an analytical price-arbitration model to assess the effects of storage following different optimization programs related to its ownership structure. Relevant findings are presented: a) If the supply sector and the storage participate in a perfectly competitive market, storage is a global welfare-maximizer no matter the ownership structure it belongs; b) storage generates losses on producer's profits; c) storage produce gains in consumers' surplus. All of which result in variations when there is market power on the supply-side, and when a strategic merchant storage is assumed. Furthermore, merchant operated storage wouldn't see necessary incentives to manage inventories as for overall welfare maximization, tending to underuse its capacity compared to the socially optimum; generators' owned storage would tend to underuse it as well because of the negative impact it has on generators' profits; while consumers' owned storage is likely to be overused. He et al. (2011; 2012) find similar results by using a modeling approach for the optimization program for the management of storage capacity and proposes an auctioned chain where regulated and deregulated stakeholders can be coordinated for storage to deliver the maximum system benefits. Nevertheless, when assessing welfare effects of new flexibility options on a system with existing capacity, not only the effects of price-arbitration need to be analyzed but also the effects of changing capital allocation (i.e., investment and retirement decisions) and stacking revenues from different markets.

Therefore, even if the adoption of high resolution integrated approaches rather than specific business models, considering multiple services and using broad time horizons under co-

optimization frameworks constitute the main converging aspects agreed in the literature related to storage valuation, there is no clear consensus on the methodology to assess storage on power systems. Furthermore, the literature on storage economics lacks on recognizing and criticizing the underlying assumptions adopted in terms of system's boundaries, system services to be balanced, and the time horizon and resolution used. Yet, there is no systematic use of what it is denoted by the term "value". Moreover, the words "benefits", "value" and "profits" are inconsistently utilized, sometimes pointing the same subject.

2.3. METHODOLOGY FOR ASSESSING ELECTRIC ENERGY STORAGE TECHNOLOGIES

2.3.1. DEFINING THE ROLE OF STORAGE

According to the literature, the benefits of electricity storage are diverse and include some relatively easily quantifiable ones such as investments deferrals, fuel savings, savings on the associated "wear and tear" cost savings, but there are others non-as-tangible such as enhancing system stability and security, facilitating firm capacity of VRE, improving insurance against VRE doldrums and fuel prices variations among others. All of these services can be simultaneously manifested or mutually exclusive. Figure 22 illustrates those sources regarding the system requirements and the voltage level they are connected.

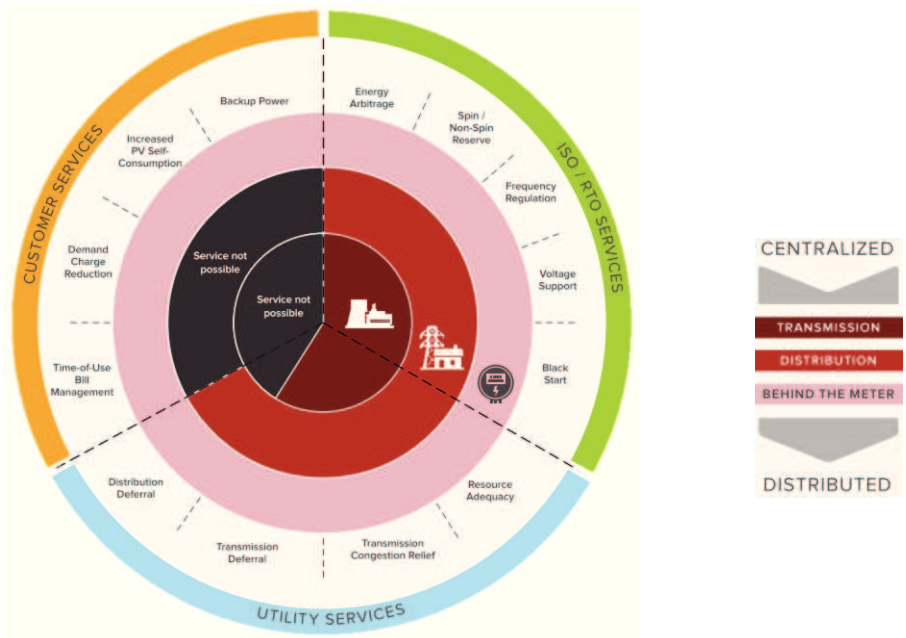


Figure 22. Services that can be provided by EES technologies. Source: (Fitzgerald et al. 2015)

Moreover, the development of EES technologies can trigger benefits that are spilled out of the power sector itself like inducing industrial development, job creation, improving energy independence, among others. Therefore, a flawless accountant definition, as well as a clear delimitation of the boundaries, should be made when assessing the value of storage.

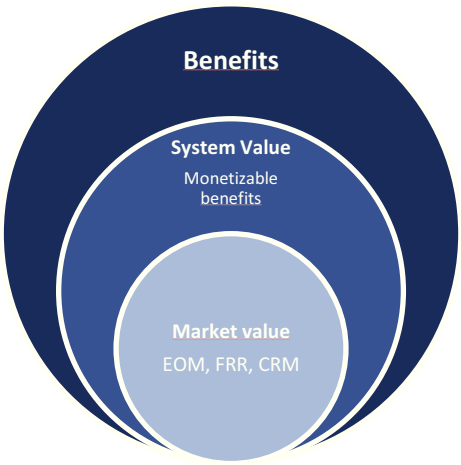


Figure 23. Benefits and value of storage

In this study, the system value of EES, hereafter denoted as the value of storage, is defined as the net monetizable system benefits generated directly or indirectly by storage, provided to a cost-optimized system including optimal capacity allocations, as well as optimal dispatch and inventory decisions. In this sense, the meaning denoted by the value of storage refers to a market equilibria condition obtained by the joint deployment of generation capacity, DSM, and EES to balance multiple system services, considering only the power system. The market value of storage, hereafter denoted as the profits of storage, is the resulting net profit obtained by subtracting stacked revenues coming from market participation with its associated costs.

2.3.2. THE DIFLEXO MODEL

Once these definitions established, the way the power system is represented should be discussed. This section briefly presents the DIFLEXO model, which is a partial equilibrium model that represents the wholesale electricity market. It is an integrated generation expansion model (GEP) that endogenously co-optimizes investments in both generation capacity and new flexibility options such as electric energy storage (EES) and demand side

management (DSM) capabilities. The model focuses on the study of flexibility needs by appropriately describing the operational constraints and the system services required at high temporal resolution. There is no grid representation on the current formulation of DIFLEXO. For the sake of parsimony, only a summarized description of the model is presented above; further details about the implementation of the model are given in Appendix A, while a comprehensive description of the model can be found in (Villavicencio 2017)[47].

The main aspect of DIFLEXO is to differentiate system requirements allowing to find the most suitable mix of technologies in order to balance them at least cost. The model comprises stock allocation decisions taking into account short-term flexibility and FRR balancing requirements subject to technology specific operating constraints. It adopts a system cost perspective considering an LP formulation where capital cost, O&M costs, ramping cost, efficiency penalties for a partial load operation, wear and tear cost of units and CO_2 emission cost are quantified. Additional environmental considerations can also be added dealing with VRE curtailment cost, CO_2 caps, RPS requirements, and technology contribution restrictions[48]. VRE capacities bid in the market at zero marginal costs and VRE curtailment is allowed without penalties. The model is linear, deterministic, and solved in hourly resolution for one year.

It is similar to other investment models in the sense that its modular structure allows short, mid and long-term calculations in relation to the way capital stock allocations are accounted (Hirth 2013; Zerrahn and Schill 2015a). When evaluating technologies on the short-term, the investment module is bypassed and the energy and FRR requirements are balanced with the available capacity in place. The optimization problem results in a dispatch and inventory problem with demand shifts if DSM capability is allowed. On the midterm, initial capacity exists but capacity investment and mothballing decisions are allowed. Therefore, quasi-fixed costs are represented by capacity reallocation decisions[49]. Initial capacities are treated as given sunk cost. This corresponds to a brownfield optimization of additional capacity, dispatch and inventory decisions. On the long-term, the power mix can be fully optimized

[47] The code of the model can be consulted on demand. For more information please contact: *manuel.villavicencio@dauphine.fr*

[48] For example: Nuclear or coal phase-out.

[49] This is assuming a contestable market due to capital allocation rigidities see (Baumol, Panzar, and Willig 1988; Brock 1983).

without initial conditions. It should be therefore expressed as a Greenfield optimization. On the long-term equilibrium profits of all producers are zero as defined in (Boiteux 1960; Steiner 1957). Therefore, the model formulation can assess the complete system value of every technology, in particular, the new flexibility ones referred to the long-term market equilibria.

DIFLEXO finds the cost-optimal investments in new capacity. Finally, the welfare effect that cost-optimal EES capacity induces via price and quantity variations can be assessed by computing the outputs of the model. The resulting surplus variations across market players can be calculated with respect to the equilibrium of the system with cost-optimal storage compared to a counterfactual system, applying the same conditions but banning any new EES investment.

In any case, the equilibrium conditions are defined by the minimization of the objective function used in DIFLEXO. The model minimizes the total system cost comprising:

- Investment and mothballing[50] costs: capital cost of new generating, storage and DSM capabilities are calculated using annualized capacity recovery factors (CRF). These parameters are inputs of the model. EES investments on power and energy capacities are considered separately for every technology defining ranges of E/P ratios to constrain them. DSM capabilities[51] are enabled simultaneously by investing on the required infrastructure (Bradley, Leach, and Torriti 2013), thus, only one *crf* is assigned to them. Mothballing cost is accounted as a fixed cost equal to a factor associated with the overnight cost for every technology.
- Running costs: Running costs of conventional units are divided into O&M cost, fuel cost, CO_2 cost, and load following cost. O&M costs are a function of power generation. Fuel consumption is affected by the part-load efficiency losses. Therefore, fuel costs and CO_2 costs are corrected to account for the increase in fuel consumption when units are generating outside its rated capacity. Load following costs are proportional to the absolute value of the difference of synchronized power of two consecutive periods (ramping costs). Storage O&M costs account for both charging and discharging modes independently. O&M costs of DSM aggregates its activation cost, the Energy Management System (EMS) maintenance costs and the

[50] Also denoting early decommissioning costs.

[51] Load shifting and load shedding.

Data and Communication Company (DCC) operational expenditures. A zero fixed but high marginal cost alternative corresponding to the value of lost load (*VoLL*) [52] was included to account for brownouts[53].

System services are represented by the following equality constraints:

- Energy-only market (EOM): It represents the balance between demand and supply for electricity on every hour. Demand is modeled as the net load obtained by subtracting the net VRE generation to the expected load. The VRE generation is endogenously computed by assuming a homothetic extrapolation of the historical hourly production curve amplified by the cost-optimal capacity added for every VRE technology; VREs are assumed to have zero marginal costs (i.e., wind and solar power) and its curtailment is allowed. The supply side is represented by the effective conventional generation capacity and flexibility options[54]. The LL balancing capability representing brownouts.
- Operating reserve requirements (FRR): Consisting of frequency restoration reserves (FRR) as suggested by (ENTSO-E 2013; Van Stiphout, Vos, and Deconinck 2015). Four types of reserve requirements are considered by combining the following categories: automatic and manual activation, with upward and downward directions. Reserve types are statistically dimensioned to account for net load uncertainty (Hirth and Ziegenhagen 2015a; Van Stiphout et al. 2014; De Vos et al. 2013). Conventional units and storage units provide frequency regulation up to the usual technical limits.
- The capacity-adequacy mechanism[55] (CRM): It is a constraint describing a decentralized capacity obligation mechanism based on (National Grid 2016; RTE 2016), where the capacity level is defined as a function of the peak load, the thermo-sensitivity of load and the contribution of interconnections to capacity. The

[52] The VoLL is set to 10 000€/MWh.

[53] Loss of load events, or brownouts, are unplanned load curtailments.

[54] The cost-optimal storage technologies and DSM capabilities added.

[55] Even if the model represents a perfect and complete market without risk aversion including demand-side flexibility and storage, which is in theory able to deliver socially optimal investment levels assuming a *VoLL* properly set (see (Keppler, 2017)), a representation of a CRM was implemented in the formulation to simulate the case of France. Including a CRM is necessary to evaluate its implications over the cost-optimal power mix and, hence, over the value of the technologies under study.

contribution of generators of every technology to system adequacy is obtained by multiplying technology specific de-rating factors times the available capacities.

The problem is constrained by the following sets of inequalities dealing with the representation of operational constraints:

- Operational constraints: Include Minimum Stable Generation (MSG) levels and maximum output constraints; ramp-up and ramp-down constraints; available frequency response and reserve constraints for every technology. Storage technologies have two operational constraints dealing with minimum and maximum inventory levels, and two constraints dealing with the inventory availability restrictions to participate on the FRR supply while charging or discharging. DSM capabilities for load shifting have an associated constraint that limits the shifting period; meanwhile, a time recovery constraint restricts the maximum consecutive periods for load shedding (Zerrahn and Schill 2015b).
- Energy policy constraints: Constraints describing the RPS targets; the nuclear moratorium policy; a CO_2 emission constraint is implemented but applied discretionarily.

2.3.3. THE VALUE OF STORAGE

Following the methodology of (Strbac et al. 2012), the system value of storage is accounted by the net system savings it induces. These savings are computed by calculating the difference in the total system cost between a cost-optimal system obtained when considering a full set of technologies in the investment portfolio, including storage, against a counterfactual system, where the same services need to be balanced but storage investments are not allowed[56]. In the case where no storage investment proves optimality, the value of storage trivially equals to zero under the assumptions adopted because both cases converge to the same optimal system, which is a system without storage. Therefore, adding EES capabilities is valuable to the system if and only if the total system cost in presence of storage is lower than that obtained in the counterfactual case. Consequently, the value of storage is said to be captured in a systemic way. Under the assumption of perfect

[56] This approach is, at the same time, founded over the formal definition of externalities. Therefore, the total value of storage is defined as the net aggregate system savings it prompts when cost-efficient.

and complete markets, the value of EES equals the net savings on system cost generated, because otherwise, the system cost would be higher without it.

As introduced on the literature review, in the case where significant shares of VRE are present on the system[57], storage can deliver the following benefits:

I. Reduce operating cost by improving the value factor of VRE, which induces fuel and CO_2 emissions savings;
II. Enhancing system's capability to absorb variability, so reducing capital and/or mothballing cost of existing capacity;
III. Reduce capacity investment by contributing to capacity adequacy;
IV. Offset the part-load efficiency losses and displace low load factor backup generation units with low efficiencies;
V. Supply low-cost load following capabilities to enhance reliability and decrease wear and tear costs;
VI. Supply system reliability by participating in the FRR requirements.

Every one of those benefits is accounted on the integrated assessment framework offered by DIFLEXO. Nevertheless, the value of storage is quantified in relation to the cost variations it prompts over the cost categories considered by the objective function of the model. DIFLEXO accounts for the following value categories: O&M costs, CO_2 costs, DSM costs, load following costs (LFC), fuel costs, mothballing costs (MBC) and overnight (ON) costs. Other value sources of storage related to spatial arbitrations capabilities (i.e., congestion management, T&D investment deferrals) are not accounted since DIFLEXO doesn't include network representation.

Moreover, storage investments can induce savings on certain cost categories generating social welfare gains but can simultaneously produce overruns on others, what determines the value of storage is the net benefit it generates on behalf of the cumulated variations.

2.3.4. THE WELFARE EFFECTS OF STORAGE

In (Grünewald, 2011), an introduction of the welfare effects of storage and demand elasticity is given for a short-term setting on the energy-only market. It is presented how the price arbitration enabled by storage flattens the price duration curve, which is traduced by a

[57] Obtained either by an optimal economic deployment, or being imposed by voluntarist energy policies.

clockwise rotation of the marginal production cost (MPC)[58] around a pivot point which is located depending on the state of the power system (see
Figure 24), triggering two opposite effects over social welfare: decreasing price levels during peak periods while discharging makes welfare gains, but when charging the supplementary demand increases price levels during off-peak periods, producing welfare losses. In both cases, the elasticity of demand improves the figure for welfare gains.

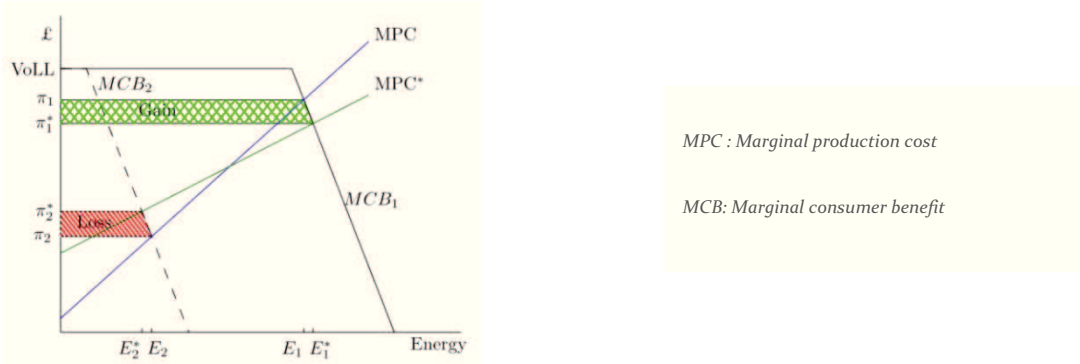


Figure 24. Welfare effects of storage during peak and off-peak periods. Source: (Grünewald 2011)

This framework needs to be enlarged to account for DSM capabilities and long terms considerations were the main slope of the MPC curve would change. DSM capabilities create an elasticity of demand of different nature than storage but with similar effects. Load shifting is constrained by the assumption of holding constant well-being levels over the shifting period [59]. Load shedding is assumed as a planned load curtailment capability. It is constrained by a shedding cap and maximum consecutive calls. Thus, actions in one period of time would impact others in subsequent periods, similarly to that of storage while charging and discharging. Therefore, foresight assumptions would have relevant implications on the calculation of the welfare effects. Interpreting these issues in the theoretical framework exposed in (Grünewald, 2011) implies assuming time-load dependencies over the extent of the MCB[60] shifts and MPC rotations. Moreover, in the case where mid or long-term optimization is adopted, the power and flexibility capacities are co-

[58] The MPC on the case of the EOM correspond to the merit order curve.

[59] This means that an upward shift on demand on time "t" is compensated with the summation of downward shifts inside the the period (t-Ls, t+Ls), where Ls is the radius of the load shifting period. This makes net shifts to cancel out inside the moving window.

[60] Marginal consumer benefit

optimized, thus, the supply curve is no longer given but optimally shaped to enhance technologic complementarities with storage, enhanced the social welfare gains.

The further analytical development of the welfare effects enabled by new flexibility options is out of the scope of this paper. Nevertheless, the modeling approach adopted allows obtaining hourly prices and quantities on every setting (with and without EES) by computing the outputs of the simulations, which makes possible to numerically estimate the welfare effects prompted by storage. The three markets considered are assumed to be cleared at a marginal price, which assures the at least zero profit condition for marginal units. Quantities are calculated by representing inelastic residual demands but enabling demand-side capabilities, as well as charging and discharging actions of storages. Resulting revenues and costs allows computing profits by technology in every case. The comparison of profits by market players on every setting allows assessing the welfare effects of storage in terms of surplus variations. Surplus variations of consumers and DSM are accounted separately. Consumers correspond then to the inelastic part of the demand and are supposed to be charged for the hourly electricity prices and the annual capacity obligation cost.

To the knowledge of the author, the distributional question of analyzing the welfare effects triggered by cost-optimal investments on new flexibility technologies, while balancing multiple services of the system, has not yet been developed elsewhere.

2.4. THE CASE OF FRANCE UNDER THE 2015 ENERGY TRANSITION ACT

2.4.1. INPUT DATA

In France, the "loi pour la transition energetique"[61] (Energy Transition Act n° 2015-992) defines the target of renewable energy contribution by 2020 to be 27% and by 2030 to 40%. Additionally, the nuclear capacity is to be capped to 63.2 GW, and its contribution should decrease from 75% to 50% by 2025. On this context, the case for new flexibility technologies could be of relevance since the need for system services would likely rise and energy policy intervention would open new market opportunities.

[61] Journal officiel "Lois et Décrets" - JORF n°0189 du 18 août 2015 (Officieal Act n°0189 of 18 August 2015) :

https://www.legifrance.gouv.fr/eli/jo/2015/8/18

The system has been calibrated to the French power system using publicly available data of the year 2015[62], where hourly demand, water inflows of reservoirs, VRE generation profiles and day-ahead forecast errors are available. The system is characterized by a peak demand of 92.63 GW and a total energy demand of 541.4 TWh. On the 2020 horizon, demand is supposed to stay at the same levels, while it is assumed to slightly increase 1% by 2030. Therefore, the system is optimized on a midterm perspective by adopting a brownfield situation where the initial capacity is set to that of the French power system of 2015. There is no remaining potential to further develop reservoir hydro capacity. The maximum potential for PHS and DCAES investments are estimated at 9.88 GW and 2 GW respectively (See Figure 36). Cost and technical parameters are extracted from (Carlsson 2014; IEA/NEA 2015; Schröder et al. 2013; Simoes et al. 2013). Fuel prices are average 2015 market prices and CO_2 prices correspond to a flat rate of 20 €/t. A fixed WACC rate of 7% was presumed across all the technologies.

[62] RTE data source: www.rte-france.com/en/eco2mix/eco2mix

Technology	*Overnight cost* [€/KW]	*Lifespam* [yr]	*crf_i* [€/KW yr]	*$O\&M^f$* [€/KW yr]	*$O\&M^V$* [€/MWh]	*fuel_cost* [€/MWh]	*CO_2 content* [t CO_2/MWh]	*Ramping cost* [€/MW]	*Initial capacity* [GW]
Nuclear	4249	60	295,1		10,0	7,0	0,015	55	63,13
Hard coal	1643	40	101,7		6,9	19,8	0,96	30	6,34
CCGT	1021	30	67,9	*included*	4,7	51,7	0,359	20	10,46
OCOT	637	30	42,4	*on*	7,3	67,3	0,67	10	-
OCGT	708	30	47,1	*the crf*	6,1	51,7	0,593	15	8,78
Reservoir hydro	3492	80	202,6		0,0	0,0	0	8	8,22
PHS									4,3

Table 10. Cost assumptions of generation technologies. Sources: (IEA/NEA 2010, 2015; Schröder et al. 2013)

Technology	Initial capacity	CAPEX -2020					OPEX -2020			Source
		System	Battery	Lifespam	WACC	*crf^E*	*crf^S*	*$O\&M^V$*	*$O\&M^F$*	
	[GW]	*[$/KW]*	*[$/MWh]*	*[yr]*	*[%]*	*[€/KWh yr]*	*[€/KW yr]*	*[€/KWh]*	*[€/KW]*	
Li-ion	–	510	200 000	10	7%	28,5 €	72,6 €	2,6 €	2,4 €	(Viswanathan, Balducci, and Jin 2013)
NaS	–	950	332 500	10	7%	135,3 €	47,3 €	2,0 €	14,3 €	(Carlsson 2014)
VRFB	–	810	109 700	10	7%	115,3 €	15,6 €	2,0 €	16,2 €	
PHS	4,3	1 500	-	60	7%	106,8 €	- €	- €	22,5 €	
DCAES	–	600	35 000	55	7%	43,0 €	2,5 €	1,2 €	7,8 €	
Flywheel	–	600	3 500 000	20	7%	56,6 €	330,4 €	2,0 €	8,4 €	
Lead_acid	–	390	164 000	8	7%	68,6 €	28,8 €	0,8 €	5,5 €	
ACAES	–	843	40 000	50	7%	79,6 €	3,8 €	3,1 €	3,9 €	(Zakeri and Syri 2015)

Table 11. Cost assumptions of EES technologies by 2020

Technology	Initial Capacity	CAPEX -2030					OPEX -2030			Source
		System	Battery	Lifespam	WACC	crf^E	crf^S	$O\&M^V$	$O\&M^F$	
	[GW]	[$/KW]	[$/MWh]	[yr]	[%]	[€/KWh yr]	[€/KW yr]	[€/KWh]	[€/KW]	
Li-ion	–	418*	196 000*	10	7%	23,5 €	71,2 €	2,6 €	2,0 €	(Viswanathan, Balducci, and Jin 2013)
NaS	–	930	331 500	10	7%	132,4 €	47,3 €	2,0 €	14,0 €	(Carlsson 2014)
VRFB	–	730	86 180	10	7%	103,9 €	12,3 €	2,0 €	14,6 €	
PHS	4,3	1 500	-	60	7%	106,8 €	- €	- €	22,5 €	
DCAES	–	530	31 060	55	7%	38,0 €	2,2 €	1,2 €	6,9 €	
Flywheel	–	483	2 500 000	20	7%	45,6 €	236,0 €	2,0 €	6,8 €	
Lead_acid	–	370	154 000	8	7%	65,1 €	27,1 €	0,8 €	5,2 €	
ACAES	–	742**	35 200**	50	7%	70,3 €	3,4 €	3,1 €	3,9 €	(Zakeri and Syri 2015)

*Assuming a cost reduction of 18% and 2% referred to 2020's levels for system and battery respectively
*Assuming a cost reduction of 25% referred to 2020's levels for both system and battery

Table 12. Cost assumptions of EES technologies on 2030

Technology	Year	*Overnight cost*	Lifespan	crf_i
		[€/KW]	[yr]	[€/KW yr]
Wind	2020	1350	25	118,6
PV		1100	25	95,8
Wind	2030	1300	25	114,1
PV		890	25	77,5

Table 13. Cost assumptions of VRE technologies. Source: (Carlsson 2014)

2.4.2. RESULTS

HORIZON 2020

In order to respect the RPS on 2020, 44.4 GW of wind should be added to the system. At this penetration level, wind supply competes directly with baseload technologies. As it was previously introduced, the modeling framework implemented considers endogenous investments which promote a value-competition between technologies on a system costs minimization.

On this horizon both cases converge to the same results: flexibility needs are exacerbated and are optimally supplied by enabling 4.68 GW of DSM and by adding 15.87 GW of fast OCOT. No storage investments are triggered, suggesting that DSM is more value-competitive than storage under the assumptions adopted.

Hard Coal capacity competes with Wind generation on the EOM and with more flexible technologies, like gas-fired turbines, for system services supply required to handle the variability. This competition, together with the CO_2 emission costs due to its more important carbon content, makes Hard Coal capacity to be totally mothballed from the mix. It is worth noting that under the capital and fuel cost assumptions adopted, CCGT capacity is completely put on-hold[63] as well. Its market shares are relocated to more flexible existing OCGT and new OCOT.

Technology	*Investments* [GW]	*Mothballing* [GW]	*Total capacity H2020* [GW]
Nuclear	-	-	63,13
Hard coal	-	-6,34	-
CCGT	-	-10,46	-
OCOT	15,87	-	15,87
OCGT	-	-	8,78
Reservoir	-	-	8,21
Wind	44,38*	-	51,36
PV	-	-	3,43
PHS	-	-	4,30
DSM	4,68	-	4,68

* Resulting from the RPS target imposed

Table 5. Investment and retirement decisions

[63] CCGT is either mothballed or decommissioned.

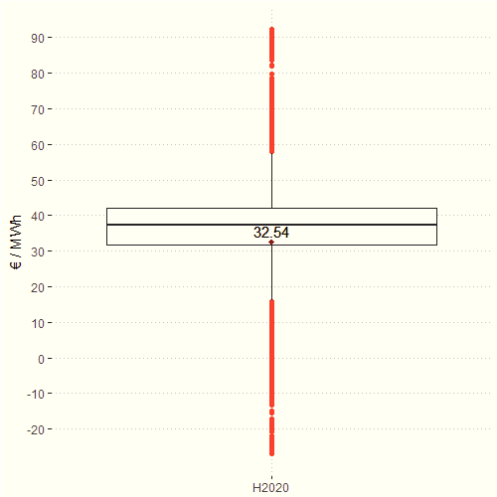


Figure 25. Boxplot of electricity prices by 2020.

Min.	*1st Qu.*	*Median*	*Mean*	*3rd Qu.*	*Max.*
[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
-27,0	31,7	37,4	32,5	42,2	92,3

Table 14. Electricity price statistics H2020

Even with the enhanced flexibility obtained by the addition of 16GW of OCOT capacity, the system still shows some difficulties to integrate variability. Extreme episodes are given by the red outliers of Figure 25.

Table 14 presents some statistics of electricity prices on this horizon. Approximately 95% of the time the electricity prices are between 17 €/MWh and 58 €/MWh, which correspond to a spread of 41 €/MWh. Nevertheless, it can be seen an important number of periods where prices go above this level, with extreme peaks going up to 92.3 €/MWh, as well as a non-negligible number of hours with negative prices. The full price spread is 119.3 €/MWh, but this spread is not sustained enough to prompt investments on storage technologies.

The total system adequacy required by 2020 is set at 97GW, from which close to 80% is satisfied by conventional units (see Figure 26), particularly by the existing nuclear capacity. Existing reservoir hydro and new wind capacity also support the system on capacity adequacy. The total CO_2 emissions are estimated at 19.6 Mton/year by 2020.

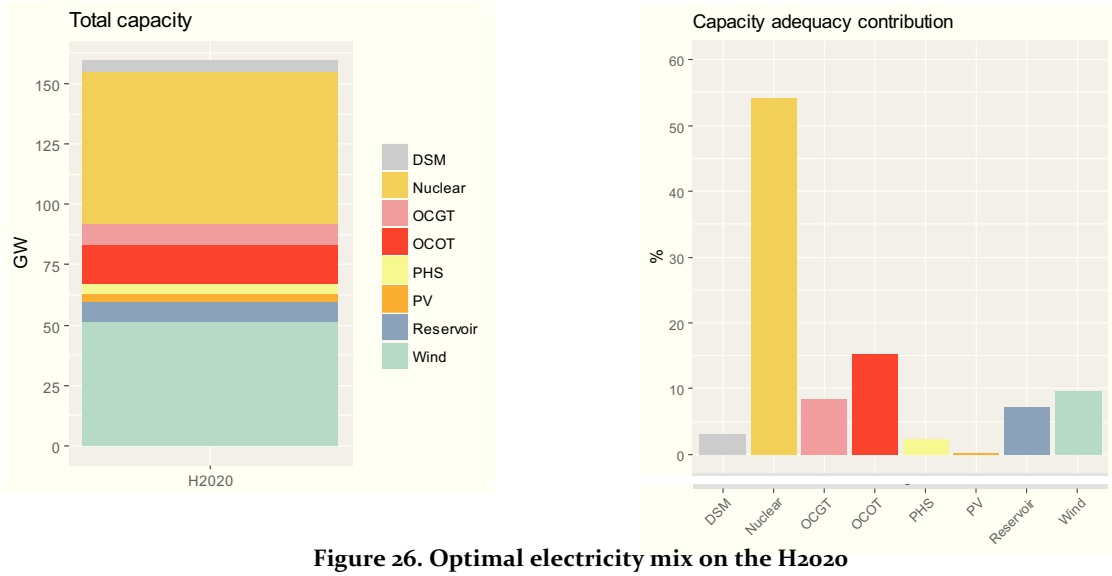


Figure 26. Optimal electricity mix on the H2020

HORIZON 2030

The strengthened RPS requirements and the voluntarist reduction of nuclear shares entail a significant policy shock on the system. Under such conditions, it is found that cost-optimal investments on storage capacity are triggered. The resulting capacity investments by this horizon are presented in Table 15. To attain the 40% of VRE shares targeted on the standard, wind capacity almost doubles with respect to the 2020 level. However, the required investment in VRE capacity is significantly reduced in the case with storage: PV investments are 16.62GW when considering storage instead of 19.9 GW in the counterfactual case; Wind capacity required is 72.23 GW with storage instead of 73.28 GW. This suggests the benefits of storage for improving the capacity value of VREs, therefore generating fuel savings and investment deferrals.

By 2030 there is an exacerbated need for flexible capacity due to the higher shares of VRE imposed. Under the assumptions adopted, 4.68 GW of DSM and 8.61GW of OCOT are deployed, but there it becomes optimal to invest in 2 GW of DCAES[64] and 1.23 GW of ACAES to further enhance system flexibility. Otherwise, in the counterfactual case, the same levels of DSM are enabled and 11.72 GW of additional OCOT capacity is needed. Although, the OCOT capacity levels are sensitively lower than those obtained on 2020. The latter is explained by the effect of the nuclear moratorium imposed by 2025, entailing a partial retirement of nuclear capacity, which makes Hard Coal and CCGT technologies to further

[64] It is worth noting that the total potential resource assumed for DCAES is exploited, therefore, the constraint relating this maximal capacity binds.

remain on the system. The higher CCGT capacity by 2030 also supplies part of the flexibility required by the system, lowering the required capacity of OCGT on the former and the counterfactual cases.

Regarding the nuclear sector under the moratorium, 14 and 15.11GW are phased-out by 2030 with and without EES respectively, against no decommissioning required on 2020 (with no moratorium). The initial CCGT capacity thus remains in the system and Hard Coal is only partially retired. Therefore, the nuclear decommissioning opens new market opportunities for mid and baseload generation technologies which, under the multi service framework considered, would also supply some flexibility to the system, reducing the cost-optimal capacity of OCOT compared to that of 2020. EES replaces around 3.1 GW of added OCOT capacity, while the remaining 4.15 GW are replaced by CCGT. The lower retirement of nuclear and hard coal when EES investments are allowed can be explained by the savings on the running costs per available capacity obtained, facilitating the more efficient dispatch of baseload capacity.

EES seems to be complementary with baseload capacity and contributes to firm capacity, confirming the intuition that EES competes with high short-run marginal cost units and complement low show-run marginal cost ones.

Technology	*Investments* [GW]		*Mothballing* [GW]		*Total capacity* [GW]	
	EES	noEES	EES	noEES	EES	noEES
Nuclear	-	-	-14,04	-15,11	49,09	48,02
Hard coal	-	-	-4,06	-4,63	2,28	1,71
CCGT	-	-	-	-	10,46	10,46
OCOT	8,61	11,72	-	-	8,61	11,72
OCGT	-	-	-	-	8,78	8,78
Reservoir	-	-	-	-	8,21	8,21
Wind	72,73	73,28	-	-	79,71	80,26
PV	16,62	19,90	-	-	20,05	23,33
PHS	-	-	-	-	4,30	4,30
DSM	4,68	4,68	-	-	4,68	4,68
DCAES	2,00	-	-	-	2,00	-
ACAES2	1,23	-	-	-	1,23	-

Table 15. Investment and retirements decisions on H3030 with and without EES

By 2030, the capacity adequacy requirement is estimated at 98.36 GW. In the same manner than for the 2020 horizon, the capacity adequacy shares are dominated by conventional technologies. The contribution of nuclear only reduces around 12 points compared to 2020 levels, corresponding to the de-rated due decommissioned capacity. As expected, Hard coal and CCGT capacity further contributes to adequacy by 2030 as to compensate the part loss by nuclear.

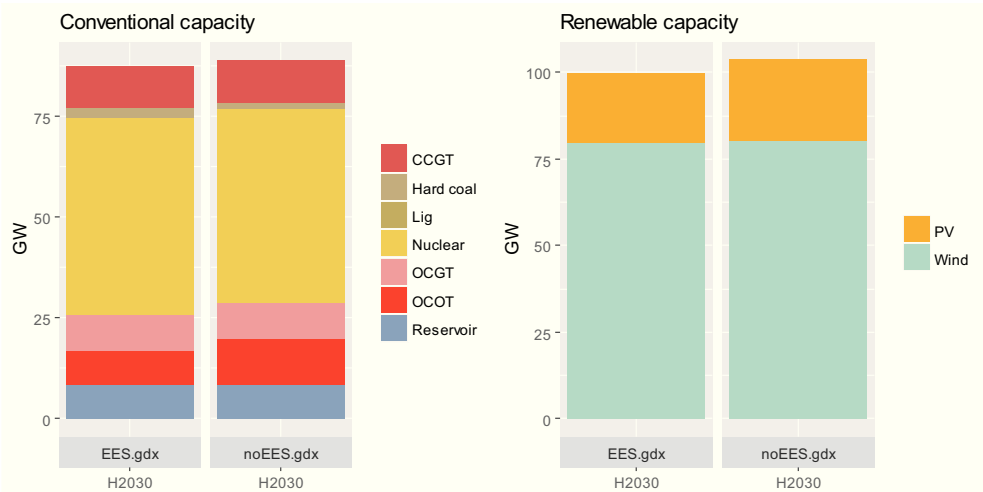


Figure 27. Optimal generation capacity

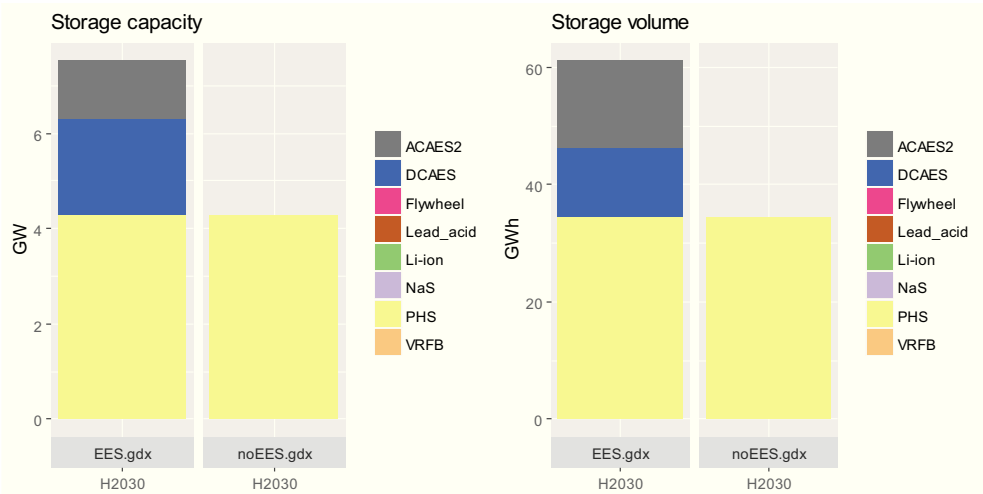


Figure 28. Optimal EES capacities

Figure 29 depicts the contribution if storage technologies on capacity adequacy by 2030. DCAES and ACAES, with a small increase of nuclear and hard coal, replace the contribution

of OCOT to capacity adequacy in terms of shares. The remaining technologies stay at similar levels.

The emissions levels of 2030 represent almost a threefold increase compared to 2020 levels. The high increase in emissions is caused by the nuclear moratorium restricting the nuclear shares to 50% from 2025. This policy shock opens the market for higher contributions of hard coal and CCGT for the base and mid-load supply.

Furthermore, given the relative levels of fuel costs and CO_2 costs considered, storage investments also cause higher emissions. By 2030, EES causes an increase in emissions from 56.4 Mton/year in the counterfactual case to 58.2 Mton/year in the former. This increase is due to the more intensified utilization of lower fuel cost but CO_2 intensive capacity, such as hard coal, for charging storage during off-peak periods, to replace costlier but less CO2 intensive OCOT capacity during on-peak periods.

The CO2 cost of 20€/ton considered is insufficient to shift profitability burdens from hard coal to CCGT for mid-load supply. Ceteris Paribus, with a sufficiently high CO2 cost, coal technologies would be put out of the market, therefore, cleaner baseload would come from nuclear and VRE capacities. Thus, storage would induce almost no CO_2 emissions while charging, and the off-peak/on-peak arbitrage would also improve emission reductions against the counterfactual case without storage

The optimal economical operation of storage consists of a price-based arbitrage between on-peak and off-peak periods not in CO_2 related emissions. Therefore, contrary to the most accepted opinion that storage would instantaneously be charged by renewables to replace conventional capacity, in the absence of an adequate CO_2 cost penalty, off-peak generation would still have lower short-run marginal costs and be more carbon intensive than on-peak generation, thus, the arbitrage function of storage would always harm the environmental performance of the resulting power mix, only leaving to an increase of the CO_2 burden on the total system cost.

Consequently, a closer regulation of the quota allocation mechanisms, or the right calibration of a CO_2 tax, is compulsory in order to storage to contribute to the emission reduction targets.

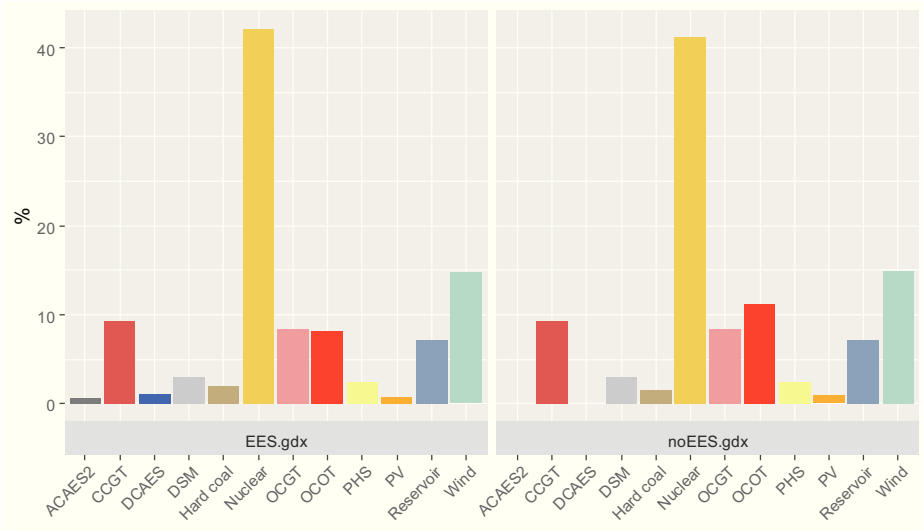


Figure 29. Capacity adequacy contribution of available capacity on H2030

The effect of storage on market prices

The effect of storage on electricity prices is presented in Table 16. CRM prices are presented in Table 17. Compared to the results obtained for 2020, by 2030 prices of the EOM present no outliers on the boxplots but spreads are persistently higher, suggesting that extreme peak units are not only punctually used as in 2020, but regularly called.

The price-spreads highly increase in 2030 given that more variability is added to the system consisting of the renewable energy targets. This is revealed by the differences of interquartile space, which is around 170€/MWh by 2030 (see Table 16) against the 41€/MWh of 2020 as previously commented. This increase is driven by higher prices during scarcity periods but also by sustained negative prices during excess periods. The minimum price levels are slightly higher but also more frequent than in 2020, suggesting that price variability is no longer restricted to extreme episodes, as represented by the outliers of Figure 25, but due to the higher shares of VRE, it is the rule.

Storage investments have a partial but unambiguous price stabilization effect. Comparing the former case with storage against the counterfactual case, it can be seen that EES investments reduce the interquartile spread. Storage has a stronger effect on low prices with a particular alleviation of negative prices due to the higher demand when charging during off-peak periods: in the counterfactual case, 50% of the prices are in the range of (-19.4 ; 100.1) €/MWh, while with storage this range shrinks to (-8.5 ; 98.1) €/MWh. This effect makes the average prices to slightly increase from 65.5 €/MWh without storage to 68.1 €/MWh. It

is to be noted that storage has a lowering effect on the peak and extreme peak prices due to price arbitraging.

	Min.	*1st Qu.*	*Median*	*Mean*	*3rd Qu.*	*Max.*
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
EES	-17,3	-8,5	98,1	68,1	106,1	158,7
noEES	-19,4	-19,4	100,1	65,5	108,7	172,4

Table 16. Electricity price statistics on H2030

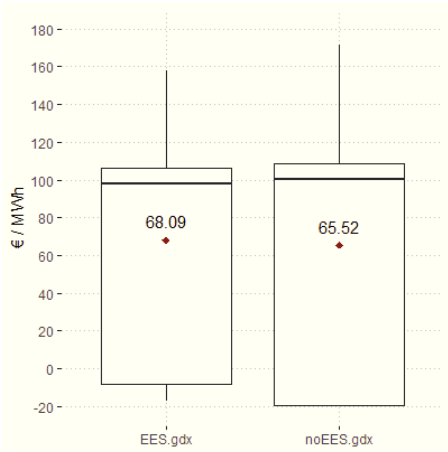


Figure 30. Boxplots of electricity prices

	Cost of Capacity obligations	*RPS cost*	*Nuclear cap*
	[€ / MW.year]	[€/%VRE]	[€/MWh]
EES	29 649	7,46	68,76
noEES	44 962	12,92	65,76

Table 17. Energy policy related costs

An unexpected result concerning the cost of the nuclear moratorium is presented in Table 17. As for the given hypothesis, storage produces an increase in the marginal cost of nuclear decommissioning. The reason is that the simultaneous consideration of storage investments alongside dispatch decisions induces savings in load following cost and part-load efficiency losses. Given that the French nuclear capacity has been modeled with a certain amount of flexibility but with important costs for load following, the presence of storage induces a smoother operation of nuclear capacity, hence, it enhances the value of nuclear on the system. Therefore, when exogenously imposing a nuclear moratorium, the MWh of a more efficiently operated nuclear capacity due to EES is higher than that without it, thus, the opportunity cost of capping the existing nuclear capacity is higher with storage.

Storage investments also produce significantly lower cost of capacity adequacy obligations, allowing a cost reduction of 35.5% with respect the counterfactual case; A less expensive RPS implementation is allowed by storage by making the full cost[65] of an additional share of VRE pass from 12.92 €/MWh without storage to 7.46 €/MWh with storage in average (see Table 17). The induced surplus variations over producers and consumers are presented in the following section.

The value of storage

The value of EES investments can be assessed following the cost categories introduced in section 3.2. Figure 31 shows the variations in system costs produced by storage. There can be seen some cost overruns and savings, as well as the net sum indicating the system value of storage. The resulting net value of storage is estimated to 352.2M€/year by 2030, which corresponds to around 1.3% of the total annualized system costs. Most of the value of storage comes from capital savings obtained by limiting additional capital costs of VRE investments, as well as some savings in mothballing costs of nuclear and coal. Savings in fuel costs correspond to the arbitrage effect of storage inducing a more intensive usage of baseload capacity while charging and replacing peak capacity while discharging. In that sense, EES also allows for a broader integration of VRE by partially avoiding its curtailment. The savings on ramping and DSM costs are rather intuitive because of the higher flexibility supplied by storage.

[65] The full cost of VRE correspond to the sum of capital, integration and profile cost associated with the VRE share which is given by the marginal value of the constraint representing the VRE target.

Nevertheless, the unitary variable O&M costs of baseload unit are higher than that of peaking units[66], therefore, the price arbitrage mechanism of storage also increases total variable O&M[67].

Given the assumption of a flat CO_2 tax, the higher CO_2 costs mean higher CO_2 emissions. This is due to a more intensive use of hard coal. Unless the relative competitiveness of high-polluting baseload units is penalized by regulatory obligations (binding CO_2 cap) or by market incentives (effective CO_2 costs), the presence of storage is likely to intensify the usage of baseload technologies regardless its environmental impact (Carson and Novan 2013). By 2030, EES capacity ensures higher market shares for hard coal than in the counterfactual case. The opposite is valid for CCGT capacity (see EOM revenues on Figure 33). This is how the CO_2 overruns are explained.

Therefore, a closer regulation of the environmental externalities is mandatory in order to harmonize least-cost renewable energy integration with CO_2 reduction objectives.

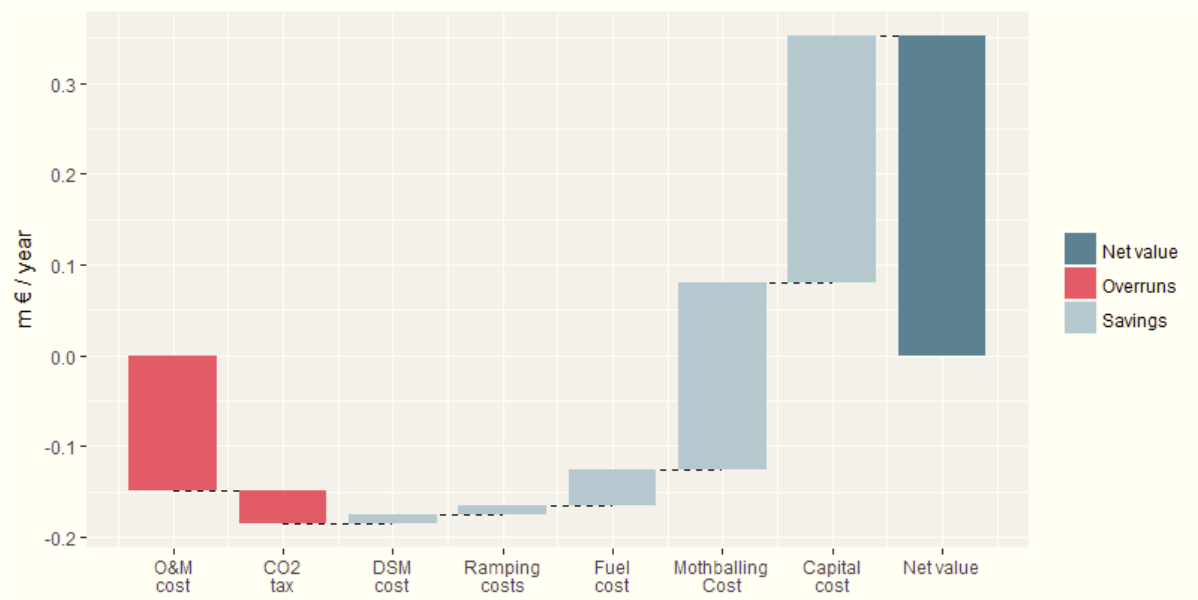


Figure 31. System value of storage investments by 2030 [68]

[66] As for the cost assumptions presented in Table 10 and Table 12.

[67] It is to be noted that variable O&M costs are separated from fuel costs.

[68] O&M costs, CO_2 costs, DSM costs, load following costs (LFC), fuel costs, mothballing costs (MBC) and overnight (ON) costs.

Figure 31 also evidences the way the system value of storage is sparse over different cost categories. These value categories are out of the boundaries of the storage facilities, which suggest the presence of positive externalities generated by cost-optimal storage. Following the reasoning of Keppler and Cometto (2012), who used the Scitovsky's categories of externalities [69] to explain the nature of the impact of VRE on the power systems, the positive externalities of EES can also be acknowledged by using the categories of pecuniary and technical externalities. The first allows the price arbitrage of storage to take place and provides storage with market rewards for doing it; while the last enhances the operational effectiveness and reliability of the system, particularly loosening the effects of variability, but whose fair valuation may require some kind of intervention.

Furthermore, the existence of such positive externalities also stresses governance issues about the coordination of optimal deployment and management of storage capacity from a system-wide perspective, which follows a social welfare maximization program, against a private form of coordination mainly focused on private profit maximization. The latter implies policy challenges dealing with investment incentives, ownership structure, and regulatory issues to attain such first-best social optimum.

On this framework, allowing endogenous investment in EES allows setting the benchmark for defining its system value, but also sets the conditions for social welfare maximization. This means that social welfare is unambiguously improved when storage is cost-optimal.

The welfare effects of storage

Assessing the welfare effect of storage is answering the distributional question of whose surplus variation becomes better-off and whose is worst-off after comparing the counterfactual case with that of cost-optimal storage. To achieve this task the total revenues coming from the different markets should be calculated and stacked for every technology. The total technology specific revenue stream should be compared with total cost by technology type to obtain the net surplus by technology in every setting. The surplus variation is the difference of the net surpluses.

Therefore, technology specific costs are calculated accounting for each of the costs categories considered on the objective, they are illustrated in Figure 32. Investments and

[69] See (Scitovsky 1954).

mothballing costs are particularly important cost categories of the system; they are incurred by endogenous decisions coming from both: economic efficiency concerns (e.g., cost-optimality) as well as regulatory obligations (i.e., RPS, nuclear cap).

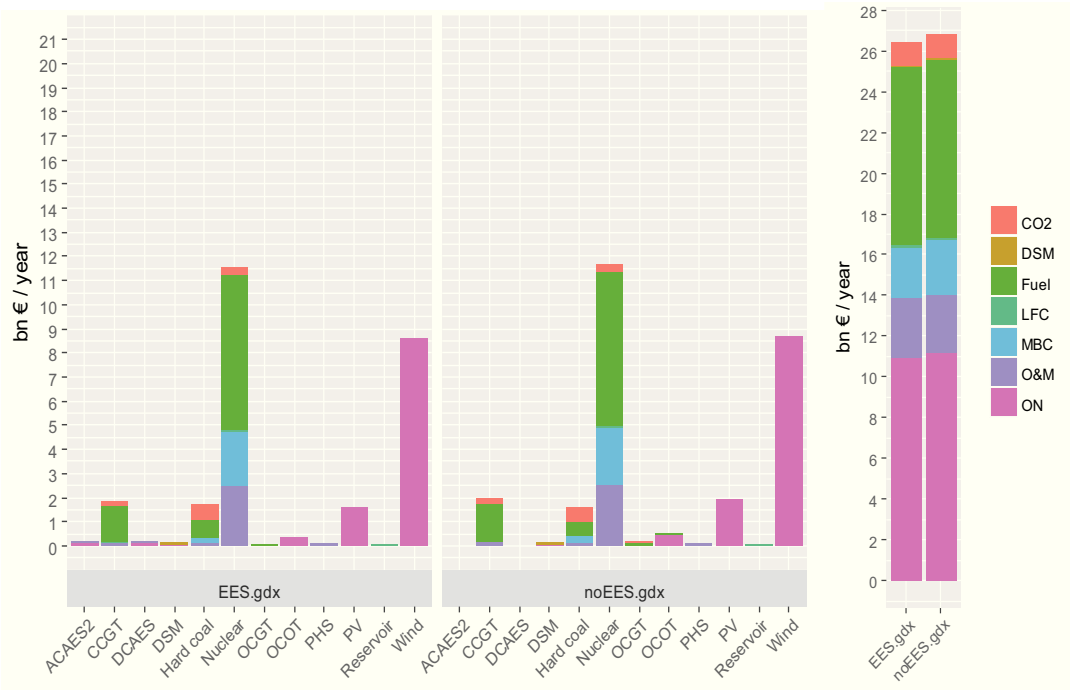


Figure 32. Cost by technology

It has been previously the economic mechanism impacting the aggregated cost categories. In this section, a closer look at cost variations by technology is presented. Variable O&M costs of baseload technologies slightly increase with storage, while the MBC cost of nuclear slightly decreases because of the lower decommissioning level. O&M costs of CCGT decreases with storage due to a market shares reduction to the benefit of hard coal. O&M costs of OCGT and OCOT also decrease when storage is available. Part of the overnight costs of OCOT and PV are saved too due less capacity is required.

As it was introduced in the methodological section, the modeling framework considers equilibrium on the energy-only market (EOM), the reserve markets (FRR) and the capacity market (CRM). In such a framework, the marginal values of each of the balancing constraints correspond to the selling prices on each market[70]. Therefore, the revenues of every technology can be accounted by multiplying its market shares times the marginal prices obtained for each market for every gate closure. The stacked revenues for every technology are presented in Figure 33.

[70] Assuming a market setting based on marginal pricing

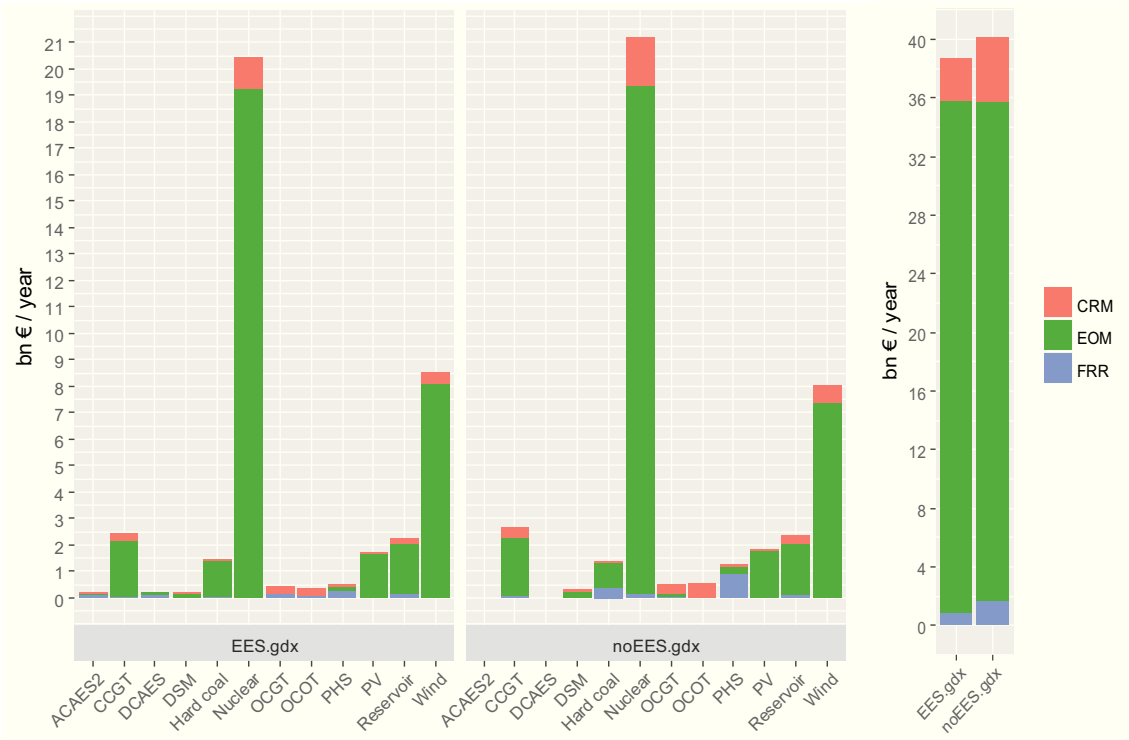


Figure 33. Revenues by technology by 2030

The EOM revenues show very little variation across all technologies but hard coal. This is not only the result of lower capacity decommissioning but also the increase of the market shares of hard coal. The EOM revenues of nuclear slightly decrease as a result of the decrease in its market share due to the better integration of VRE with EES. Wind and PV also increase its EOM revenues when storage is present. The revenues of reservoir hydro remain at the same level. Thus, the presence of storage allows for an intensified usage of baseload technologies.

The price levels of FRR significantly decrease with storage, making the total revenues decrease too. In the counterfactual case, most of the FRR revenues are captured by existing PHS, with some contribution of hard coal and nuclear for by their supply of spinning reserve, and hydro for fast reserve. There is an important cost reduction on the cost of capacity credits when storage is allowed (see Table 17) which results in an important shrink of CRM revenues, with storage taking just a part of the share but allowing existing nuclear to keep its shares. In the former case, the total level of revenue not only shrinks but is more dependent on the EOM level than the counterfactual case.

It can be also highlighted in Figure 33 the particularities of the brownfield optimization. This is, cumulating the revenues obtained on the three markets[71] gives just the right economic incentives to new investments to recover its variable and fixed costs. When comparing revenues with total costs for every technology on each case (see Figure 34), it can be seen that only non-decommissioned existing capacities make positive profits, which correspond to their marginal rent. Partially decommissioned technologies make some profits by participating in the market but also make losses when decommissioning, as it is the case for nuclear and hard coal. The net effect depends on the market shares remaining after partial decommissioning. Meanwhile, and according to the theoretical case[72], the not policy-imposed cost-optimal investments exactly obtain sufficient revenues to recover their full costs, generating zero marginal rent. For instance, let's see the case of OCOT units. In both cases, total revenues equal full costs. Thus, even if their market share is different in every case, no marginal rent is generated, and no surplus variation appears.

The case of policy-imposed technologies such as VREs is particularly interesting: high investment levels on VRE capacity are necessary to satisfy the binding RPS targets, leaving to a local minimum. Thus, the RPS targets introduce exogenous obligations breaking the zero-profit condition governing endogenous investments. As a result, the full cost of wind and PV are slightly higher than their revenues. This gap can be interpreted as the total amount of subsidies that are required to satisfy this goal. In the counterfactual case, the revenue gap is exacerbated compared with the case where EES investments are allowed. EES considerably reduces this gap (see Figure 34) by increasing the market value of VRE, and therefore, reducing the cost of the subsidy required. Furthermore, less VRE investments are required to attain the same VRE penetration targets (including VRE economic curtailment) as showed in Table 15. Therefore, the social costs of the required supporting mechanism are reduced by storage investments.

The entry of storage in the capacity adequacy and FRR markets has a depreciative effect on price levels on both markets. Therefore, negative surplus variations appear with respect to the counterfactual case for the remaining technologies. This effect is proportional to the market shares detained by every technology on each market.

[71] Under markets with a marginal price settlement method.

[72] See Boiteux (1951).

Figure 35 presents the distribution of surplus variations produced by cost-optimal investments in EES capacity by 2030. The net surplus variation is 670 m€/year which is mainly driven by the increase of consumer's surplus due to lower cost of the power supply but also, lower prices of capacity obligations and FRR supply.

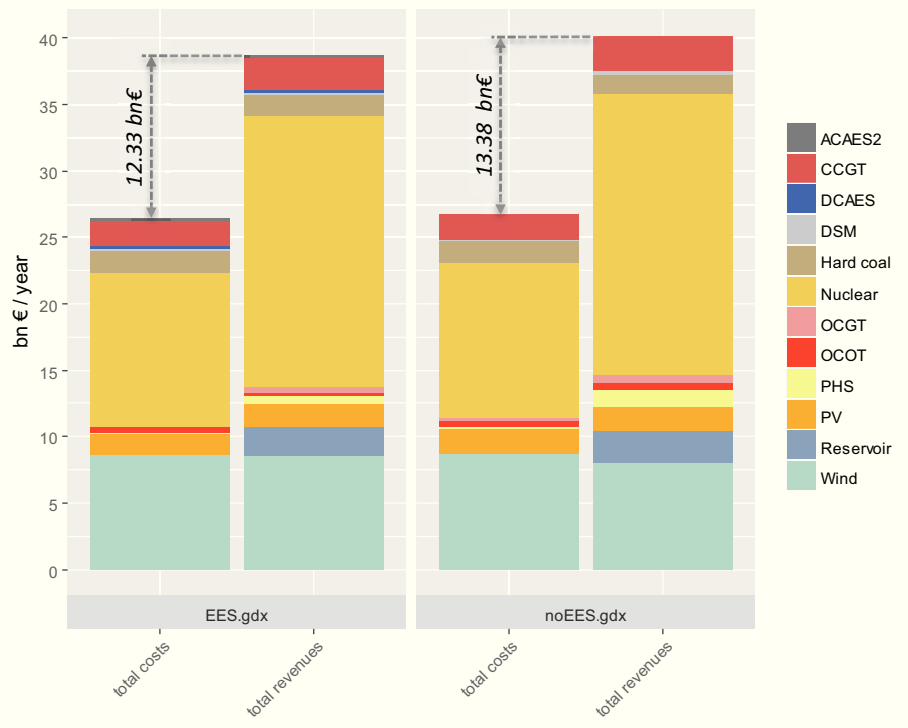


Figure 34. Revenues and costs by technology

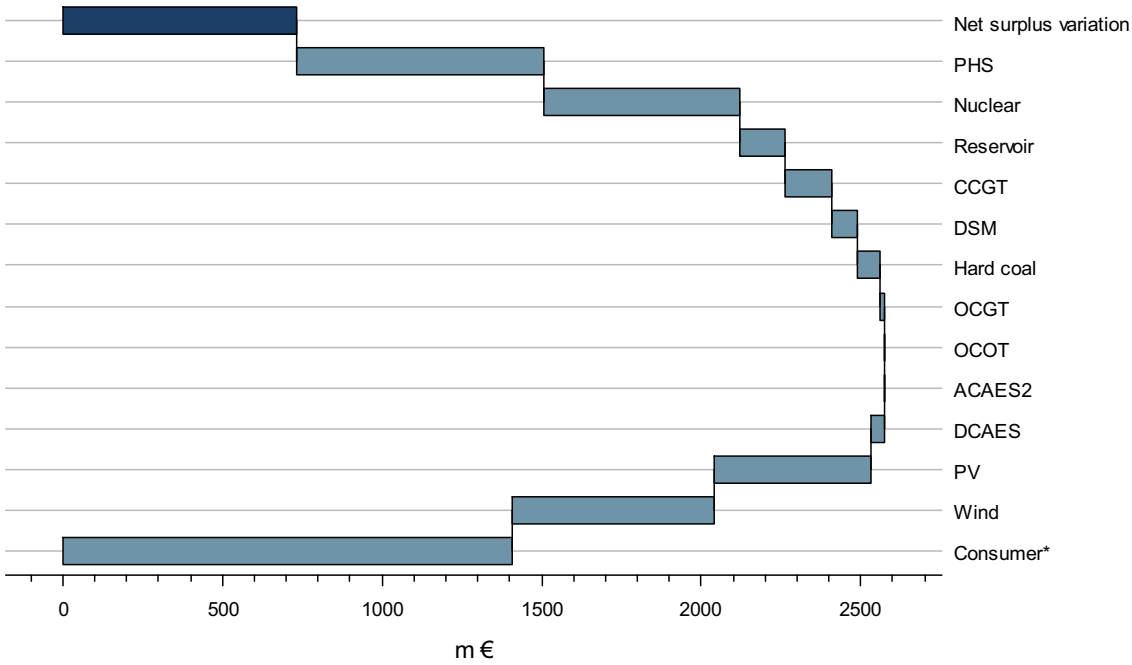
As previously commented, it can be seen that surplus variation of extreme peak units, mainly new flexibility investments, is zero[73] (i.e., OCOT and ACAES). Conventional technologies experience surplus losses due to the depreciative effect of EES over the CRM and FRR markets, which deteriorates their revenues.

Meanwhile, the surplus of VRE technologies increases due to savings on capital cost since storage allows for similar shares of VRE with lower capacity installed, and due to a slight increase of its market shares on the EOM due to a better integration of variability.

As can be depicted in Figure 34, the cumulated variation of conventional producer's surplus is negative, which is somehow a counter-intuitive result because EES allows a more efficient use of available resources inducing savings on load following costs and a steadier usage of

[73] The slightly positive value of DCAES surplus is determined by the constraint over the maximum potential capacity assumed for this technology (2 GW).

the base and mid technologies. Nevertheless, the depreciative cost effect caused by storage over the CRM and FRR markets is sufficiently high to offset those gains.



*Consumer's surplus variation corresponds to the no price-responsive part of load

Figure 35. Welfare effects of cost-optimal storage investments by 2030

Assuming the total cost of electric service supply, including power, capacity, and frequency restoration services, to be completely retrofitted to consumers[74] with no additional burdens[75], the formers experience significant positive surplus variations of around 1.32 bn€/year, which makes storage to unambiguously improve the overall welfare by about 670M€/year.

2.5. DISCUSSION

2.5.1. ENERGY POLICY IMPLICATIONS

In view of the distributional effects prompted by storage, several questions dealing with its ownership and regulation emerge. Storage units are capital intensive technologies who benefit from important economies of scale. So, the unitary cost of storage is lower for bulk facilities of several megawatts than for behind the meter installations. This holds alongside

[74] Considered as the part of load considered as inelastic and inflexible.

[75] In the absence of additional taxes or any retail margins.

every type of storage technology but also across technologies. Nevertheless, bulk storage falls in the scale of utility owned capacity. Therefore, households or small business installations could not benefit from such economies of scales.

The creation of uptake of new utilities entering the market and providing storage services seems unlikely given the current levels of market concentration in liberalized markets. Electricity markets are still conceived as oligopoly markets with an important concentration of market shares. They are the focus of continuous unbundling exigencies and market fragmentation policies. Therefore, incumbent electricity utilities, who detain important generation assets, mostly conventional capacities, would be the best suited for including bulk storage investments into their portfolios. Nevertheless, given that surplus of conventional technologies decreases with storage, pure private utilities may discover a conflict of interest in doing so.

Public utilities may acknowledge the social benefits of storage and could assume some losses on their current portfolios and come up with the supply of storage services in order to attain higher levels of social welfare but this would represent an indirect surplus transfer not only to consumers but also to VRE capacity owners (see Figure 14), which can be perceived as a secondary form of public support for renewables and are likely to perceived as further market distortions by the regulatory authorities.

As previously explained, consumers and VRE generators would be better off with storage, they would be the more concerned stakeholders for its deployment but their disseminated character impedes them to undertake the capitalistic investment required to benefit from economies of scale leading to a cost-optimum storage capacity. Furthermore, in the presence of positive externalities, coordination issues would appear for the optimal stock management across highly disseminated market players with limited information.

Further, the current market designs also impose challenges for the optimal deployment of storage:

- VRE producers: current supporting mechanisms based on Feed-in-tariffs (FiT) defines rewards upon net energy (i.e., quantitates) regardless the state of the power system, thus, they don't give incentives for EES investments. Moreover, even under support schemes exposing VRE to market signals (e.g., feed-in-premiums), storing energy behind the meter at VRE facility level, without a flexibility remuneration mechanism, would prevent the merit order effect to take place, eventually decreasing the price-arbitrage

revenues of storage, and then, annealing any incentive for doing so. Capacity remunerations and FRR returns captured by storage would currently experience important regulatory barriers and, without price arbitrage revenues on the EOM, would not be enough for these actors to undertake EES investments.

- Consumers: similar barriers would impede EES investments to be recovered if it is deployed behind-the-meter by consumers. But most importantly, investments in grid-level storage such as CAES technologies are out of the scope of consumers because of project's scale, the higher cost of capital for users and for locational reasons. Even though, assuming perfect substitution of CAES for user level batteries, electricity bills being set based on average power and energy consumed would render consumers neutral to storage investments. Aggregators and dynamic pricing could be a solution for this but, given the highly disseminated nature of consumers; still, information asymmetry and coordination issues would pose difficulties for consumers to undertake cost-optimal investments into EES.
- Merchant owned storage could be urged but, under current regulatory frameworks, it would struggle to have access to all the revenue sources necessary to stack enough profits for break-even. Risk perception would only worsen the case.
- TSOs and DSOs could be the main actors to drive the uptake of storage; nevertheless, in most liberalized markets TSO and DSO are regulated participants that are not allowed to perform market-related activities. Furthermore, "their priority in the current market structure and regulatory conditions, is on quality of supply" and system reliability, "which are pursued with low risk (e.g., network capacity expansion), rather than profit maximizing strategies" (Grünewald, 2012). All of which impede any price-arbitrage usage of storage, hindering its optimal operation.

Furthermore, strategic challenges also appear when comparing the results obtained on the two horizons considered. By 2020, cost-optimal investments are composed by 4.68GW of DSM and 15.87GW of OCOT. While by 2030, optimal OCOT capacity is divided almost by a half, not to mention the CCGT mothballing by 2020 and its full restoration by 2030. Considering the lifespan of plants, possible dynamic inconsistencies appear between the two horizons considered with very undesirable consequences. The world possibilities would them be: either entailing cost-optimal investments on both horizons and a) causing stranded OCOT capacity by 2030, or b) causing technology lock-in situations due to the

path dependency of capacity investments, or c) accepting a suboptimal mix either by 2020 or 2030.

2.5.2. LIMITATIONS

The implemented approach allows assessing the value of storage and its welfare impacts in current electricity markets. Nevertheless, even if the described main mechanisms taking place would hold even in a larger framework because they describe the fundamentals interactions of different technologies in a market setting, the results obtained should be interpreted with attention since the approach has several limitations coming from the limits of the modeling framework.

The perfect foresight assumption implemented by DIFLEXO provides an upper bound of the value of storage. Real operators, planning under imperfect foresight, would be able to capture just a fraction of this value. In (Sioshansi et al. 2009) it was shown that an EES facility using a simple two weeks backcasting technique would get at least 85% of the revenues obtained under perfect foresight given the substantial patterns of load and prices driving close to optimal inventory utilization. For the penetration levels studied by 2020 and 2030, their conclusions still hold. The use of more refined forecasting techniques and near-term weather forecasts information would allow market players to behave closer to the perfect foresight case. Even if flexibility requirements would remain with better forecasting techniques, thus, allowing for similar EOM price-arbitration revenues, there would be less need for reserve and ancillary services, decreasing the benefits of EES associated with reliability.

Nevertheless, under even higher shares of VRE, the patterns of residual load would become even more volatile. The higher variability of net load would rather benefit the case of storage technologies for smoothing net load and for risk mitigation purposes. In such a case, the relevant policy question would, in turn, be the rationale of implementing such an ambitious RPS policy considering the overruns it may entail.

The consequences of abstracting from interconnections and network constraints in the study have also important implications. Interconnections are a source of flexibility that allows for locational price-arbitrations, they also offset the overall variability of VREs by combining bigger uncorrelated balancing zones. Both effects are in detriment against the benefits of EES. Nevertheless, storage investments can also generate important savings on

interconnection and T&D deferrals. EES would allow supporting congestion management issues and improving network reliability during critical episodes, thus, it would be convenient to include a locational dimension to the benefits of EES alongside a detailed representation of the electricity network. An interesting point was raised by Eyer et al. (2005) dealing with the benefits that a relocatable modular storage would have at a T&D level for enhancing reliability and deferring expansion. Broadening the assessment of the value of storage to a regional landscape, integrating interconnection investments, T&D representation and country specific RPS targets are out of the scope of the present study and would be the subject of further research.

The results obtained assume a homothetic extrapolation of VRE generation based on the meteorological year and the installed capacity of 2015. This simplification can introduce important bias on the results. The methodology for assessing the value of storage is still valid but sensitivity analysis should be included using different meteorological years for the characterization of VRE generation and load. Other sources of uncertainty correspond to the investment cost assumed for EES technologies, the fuel, and CO2 prices expected and the limited estimation of DSM resources.

For a broader assessment of storage benefits, the simulations were conducted without the current regulatory barriers allowing only generation technologies to participate in the FRR supply. Other regulatory challenges appear for the cost-optimal development of storage: the system value of storage is sparse in different cost categories outside the boundaries of the storage technology, suggesting that there are positive externalities associated with the optimal management of EES capacity. The latter would imply that socially optimum storage investments obtained under a system perspective would not necessarily correspond with that obtained from a profit maximization approach (i.e., private optimum) without the proper coordination mechanisms[76]. Not only the ownership structure of storage would affect its optimal management, opening new regulatory issues for welfare maximization (Sioshansi 2010, 2014), but the uptake of storage capacity would also introduce asymmetric distributional effects producing winners and losers between technologies, creating opposing interest groups. Furthermore, the difficulties of markets to incentivize investments in

[76] See (Grünewald 2012) for further development of this topic

storage, together with the semi-non-rivalry[77] and the semi-non-excludability[78] of such kind of assets suggest that it should be considered at least as a "near-public" good, assuming all the policy implications it implies (He et al. 2011).

The evaluation framework proposed exposes the results by giving snapshots of the optimal power system on the two horizons considered. There is no dynamic evaluation of the value of storage in between. Therefore, the question of the transition from the cost-optimal mix of 2020 to that of 2030 has not being considered. Possible dynamic inconsistencies found when comparing results of both horizons suggest possible lack of coherence between both targets. Stranded assets situations or technology lock-in mechanisms can be created by the ambitious RPS targets imposed on the two relatively "close" horizons in face of such an ambitious policy shock introduces by the Clean Energy Transition Act of 2015. These issues should be studied in a strategic framework to depict well-informed policy recommendations. This will also be a matter of further research.

2.6. CONCLUSION

Analyzing the role of storage in power systems is a complex problem that should be analyzed in the right framework. The role of storage technologies not only depend on its own costs but on its value related to the rest of the system. Assessing the value of storage requires a rigorous methodology and a clear definition of boundaries for accounting the multiple value sources it engenders. This study proposes practical definitions of the benefits, the value and the profits of storage units. A numerical methodology for the assessment of the value of storage has also been presented.

The DIFLEXO model was proposed as the integrated tool capable of capturing competition and complementarities between different technologies when multiple services need to be balanced using high temporal resolution. The official renewable energy standards of France defined by 2020 and 2030 have been evaluated to illustrate the methodology proposed.

Relevant results are obtained for both time horizons: by 2020, 27% of VRE shares are targeted, DSM and OCOT investments completely cover the higher need for flexibility; there

[77] The very low short-run marginal cost of storage makes suppose that no opportunity cost are incurred to other stakeholders using the spare storage capacity under the capacity limits.

[78] It is easily conceivable to prevent nonpayers from the usage of storage services.

is no storage investment, hence, no EES is cost-optimal. The value that EES creates on the system is too low related to its capital cost. Nevertheless, on the 2030 horizon, when the target of VRE share reach 40% and nuclear shares are capped from the current 75% to only 50%, and further cost reductions of storage are expected, investments on compressed-air electricity storage becomes cost-optimal. In this case, storage increases the market value of VREs, reduces the operating costs of low short-run marginal units by reducing its load following costs as EES operations allows to significantly absorbs the variability of the residual load; it also provides cost-effective firm capacity and participates on reserve supply. By this horizon, the value of EES is estimated at 352.2 m€/year and to be mainly driven by savings on capital and fuel costs. Nevertheless, at the constant CO_2 tax assumed, EES produces a CO_2 emission increase of 1.8 Mton/year compared with the counterfactual case.

The average electricity price slightly increases from 65.5 €/MWh to 68.1 €/MWh with storage in the system. It also produces a reduction of the electricity price-spread of 15.8 €/MWh. This corresponds to an asymmetric price stabilization effect over electricity prices. The asymmetry can be attributed to the efficiency loss of the power conversion system and the self-discharge characteristics of EES units, which makes it demand higher volumes of energy while charging, during low prices, compared with the effective amounts delivered while discharging, at high prices. Therefore, price increase during off-peak episodes is higher than price decrease during peak episodes. EES also makes the price of capacity obligations to be cut by 34%. Even with the observed increase in average electricity prices, consumer's surplus is positively affected due to the lower price of capacity obligations and ancillary services offsetting the slight higher average prices of electricity. The cost-effectiveness of the energy policy instruments based on RPS targets would be enhanced if new flexibility technologies (such as storage) would also be considered in the directives.

Under the assumption that markets are cleared at a marginal price, which secures the condition of zero-profit, the capacity investments shaping the slope of the supply curve are co-optimized along with the dispatch decisions, the entry of storage capacity on the system entails market distortions producing winners and losers among technologies. It was found that VRE producers make important surplus gains with cost-optimal storage by improving its market integration levels and by selling at higher average prices. On the other hand, even if revenues on the EOM market remain stable for baseload conventional technologies, they experience surplus losses due to the lower revenues coming from the CRM and FRR markets as a product of additional firm capacity and ancillary services supplied from storage. The

profits of peak-load conventional technologies are not particularly affected since them just break-even in the former and in the counterfactual case.

When assessing the value of storage on the midterm, only quasi-fixed costs are optimized by readjusting capital allocations, which mean that EES can generate capital savings on the marginal investments and retirement decisions. Nevertheless, in the midterm, as the market is are non-contestable in the sense of Baumol (1988), storage cannot get its complete value because of sunk costs[79]. It could be expected that a longer-term setting, assessed under a Greenfield scenario, the same level of EES capacity would add higher value to the system by enlarging capital cost savings.

When significant shares of VREs enter the system, investments in storage allow improving their market value. Careful should be paid in cases where no enough economic incentives exist for storage to counterpart low carbon intensive technologies (i.e., nuclear and VRE) because EES would enhance the usage of baseload technologies regardless its carbon footprint. Therefore, effective CO2 cost incentives (or regulation) are required for storage to contribute to the emission reduction targets: In general, EES shows complementarity with low short-run marginal cost technologies, enhancing its market shares. In the absence of an effective pricing scheme of environmental externalities (i.e., no clean spark spread or clean dark spread), cost-effective EES can also produce an increase in CO2 emissions due to a higher use of CO2 intensive baseload capacity (e.g., coal or lignite).

Results obtained show that investments in storage not only create value from different categories but also creates welfare variations across different stakeholders. Therefore, new business models for the ownership and operation of storage; advanced regulatory frameworks broadening the eligibility of storage to supply multiple services; a closer look at environmental regulation and some kind of strategic instrument would be necessary to attain the cost-optimal development of storage in coherence with CO2 reduction goals. These results point out possible dynamic inconsistencies between RPS targets which would possibly cause technology lock-in situations (Schmidt et al., 2015) and/or stranded asset incidents in the midterm.

[79] In the current framework, sunk costs are the capital allocations denoted by the initial sub-optimal capacities which can be early decommissioned by paying an additional cost.

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2.8. APPENDIX

A. SET, PARAMETERS AND VARIABLES USED BY DIFLEXO:

Element	Set	Description
t, tt	$\in \mathbb{T}$	Time slice
i	$\in \mathbb{I}$	Supply side generation technologies
con	$\in \mathbb{CON} \subseteq \mathbb{I}$	Conventional generation technologies
vre	$\in \mathbb{VRE} \subseteq \mathbb{I}$	Renewable energy technologies
ees	$\in \mathbb{EES} \subseteq \mathbb{I}$	Electric energy storage technologies
dsm	$\in \mathbb{DSM}$	Demand-side technologies
lc	$\in \mathbb{LC} \subseteq \mathbb{DSM}$	Demand side management able to supply load curtailment
ls	$\in \mathbb{LS} \subseteq \mathbb{DSM}$	Demand side management able to supply load shifting

Table 18 - Sets

Parameter	Unit	Description
t_{slice}	[h]	Time slice considered
$C_i^{Capital}$	[€/GW]	Overnight cost of unit *con, res or ees*
crf_i	[€/GW]	Capacity recovery factor of unit *con*
fc_i	[€/GWh$_{th}$]	Average fuel cost by technology
$o\&m^v{}_{con}$	[€/GWh]	Variable operation and maintenance cost of *con* unit
$o\&m^f{}_{con}$	[€/GW]	Annual fixed operation and maintenance cost of *con* unit
C^{CO2}	[€/ton]	CO_2 cost
ef_i	[tCO_2/GWh]	Emission factor of technology by fuel type
lf_{con}	[€/GW]	Load following cost of unit *con*
$o\&m^v{}_{vre}$	[€/GWh]	Variable operation and maintenance cost of *VRE* unit
$o\&m^f{}_{vre}$	[€/GW]	Annual fixed operation and maintenance cost of *RES* unit
rec_{vre}	[€/GW]	Cost of curtailment of *VRE* unit

$\mathrm{crf}^{S}{}_{vre}$	[€/GW]	Capacity recovery factor of power capacity of *ees* unit
$\mathrm{crf}^{\mathrm{E}}{}_{vre}$	[€/GWh]	Capacity recovery factor of energy capacity of *ees* unit
$\mathrm{o\&m}^{\mathrm{v}}{}_{ees}$	[€/GWh]	Variable operation and maintenance cost of *ees* unit
$\mathrm{o\&m}^{\mathrm{f}}{}_{vre}$	[€/GW]	Annualized fixed operation and maintenance cost of *ees* unit
c_{lc}	[€/GW]	Cost of DSM for load curtailment
c_{ls}	[€/GW]	Cost of DSM for load shifting
δ	[%]	Load variation factor
$\mathrm{G}^{\mathrm{l}}{}_{vre,\mathrm{t}}{}^{\mathrm{base}}$	[GW]	Base year VRE generation of technology VRE on time t
$\mathrm{P}_{vre}{}^{\mathrm{base}}$	[GW]	Base year VRE capacity installed of technology *res*
$\overline{\eta_{con}}$	[GWhth/GWh]	Full load thermal efficiency of unit con
m_{con}	[-]	Part-load efficiency slope of unit con
b_{con}	[$\mathrm{GWh_{th}}$]	Fuel consumption intercept
$\overline{\mathrm{p}_{\mathrm{con}}}$	[%]	Maximum power of technology *con* as a function of its installed capacity
$\underline{\mathrm{p}_{\mathrm{con}}}$	[%]	Minimum power of technology *con* as a function of its installed capacity
$r^{+}{}_{con}$	[%/min]	Ramp-up capability of technology *con*
$r^{-}{}_{con}$	[%/min]	Ramp-down capability of technology *con*
$\overline{\phi_{ees}}$	[h]	Minimum energy-power ratio of technology *ees*
$\underline{\phi_{ees}}$	[h]	Maximum energy-power ratio of technology *ees*
sd_{ees}	[%/h]	Self-discharge of storage unit *ees*
η_{ees}	[%]	Round cycle efficiency of storage unit *ees*
σ_{ees}	[%]	Fraction of discharge power coming from fuel
$\overline{e_{ees}}$	[%]	Maximum capacity for energy storage of unit *ees*

$\underline{e_{ees}}$	[%]	Minimum capacity for energy storage of unit *ees*
$\overline{s_{ees}}^{ch}$	[%]	Maximum power demand of storage unit *ees* while charging
$\overline{s_{ees}}^{dch}$	[%]	Maximum power supply of storage unit *ees* while charging
r_{ees}^{ch+}	[%/min]	Ramp-up capability of storage technology *ees* while charging
r_{ees}^{dch+}	[%/min]	Ramp-up capability of storage technology *ees* while discharging
r_{ees}^{ch-}	[%/min]	Ramp-down capability of storage technology *ees* while charging
r_{ees}^{dch-}	[%/min]	Ramp- down capability of storage technology *ees* while discharging
t_{aFRR}	[h]	Minimum required reserve supply duration for aFRR supply
t_{mFRR}	[h]	Minimum required reserve supply duration for mFRR supply
$\overline{dsm}_{lc}$	[%]	Maximum part of load available for load curtailment lc
R	[h]	Number of recovery periods after curtailment
L_{lc}	[h]	Number of consecutive periods a *lc* can be activated
L_{ls}	[h]	Radius of the load shifting window
$\overline{dsm}_{ls}^{up}$	[%]	Maximum part of load available for load upward shifting ls
$\overline{dsm}_{ls}^{do}$	[GW]	Maximum part of load available for load downward shifting *ls*
$P^{Usize}{}_{con}$	[GW]	Unitary size of conventional unit con
$\varepsilon_l^{aFRR_{up}}; \varepsilon_l^{aFRR_{do}}$	[%]	Average forecasting RMSE of demand (5% tolerance)

$\varepsilon_{res}^{aFRR_{up}}; \varepsilon_{res}^{aFRR_{do}}$	[%]	Average forecasting RMSE of VRE generation (5% tolerance)
$\varepsilon_{l}^{mFRR_{up}}; \varepsilon_{l}^{mFRR_{do}}$	[%]	Average forecasting RMSE of demand (1% tolerance)
$\varepsilon_{res}^{mFRR_{up}}; \varepsilon_{res}^{mFRR_{do}}$	[%]	Average forecasting RMSE of demand (1% tolerance)
δ^{up}	[%]	Maximum regulation up capability of technology *con*
δ^{do}	[%]	Maximum regulation down capability of technology *con*
$\delta^{up^{sp}}$	[%]	Maximum spinning up capability of technology *con*
$\delta^{do^{sp}}$	[%]	Maximum spinning down capability of technology *con*
θ_{res}	[%]	Yearly share of renewable energy (RPS)
$\theta_{nuclear}$	[%]	Nuclear share cap (nuclear moratorium)
α_i	[%]	Technology related de-rating factor for capacity value
ΔT	[°C]	Maximum temperature gap from the reference year
L_{Th}	[GW/°C]	Thermo-sensitivity of demand
SA_{req}	[%]	Residual system adequacy requirement after interconnection

Table 19 – List of parameters

Variable	Unit	Description
I_{con}	[M€]	Annuitized overnight cost of production unit *con*
MB_{con}	[M€]	Annuitized *con* unit mothballing cost
$F_{con,t}$	[M€]	Total fuel cost of production unit *con*
$O\&M_{con,t}$	[M€]	Operation and maintenance cost of conventional unit *con*
$CO2_{con,t}$	[M€]	CO_2 emission cost of conventional unit *con*
$\Delta G_{con,t}$	[M€]	Load following cost of conventional unit *con*
LF_{con}	[M€]	Load following cost of unit *con*
P_i^{ini}	[GW]	Initial installed capacity of technology *i*
P_i^{inv}	[GW]	New capacity investments of technology *i*
P_i^{MB}	[GW]	Mothballed capacity of technology *i*
$G^l{}_{con,t}$	[GW]	Generation level of conventional unit *con*
$FC_{con,t}$	[GWh_{th}]	Linearized part-load fuel consumption of production unit con
$G^+{}_{con,t}$	[GW]	Generation increase of unit *con* in hour *t*
$G^-{}_{con,t}$	[GW]	Generation decrease of unit *con* in hour *t*
I_{vre}	[M€]	Annuitized overnight cost of VRE unit *res*
MB_{vre}	[M€]	Annuitized VRE mothballing cost
$O\&M_{vre,t}$	[M€]	Operation and maintenance cost of RE unit *res*
P_{vre}	[GW]	Total installed power of VRE units
$G^l{}_{vre,t}$	[GW]	Generation level of VRE unit *res*
$REC_{vre,t}$	[M€]	Curtailment cost of VRE unit *res*
$G_{vre,t}^{cu}$	[GW]	Power curtailed of V*RE* unit on hour *t*
I_{ees}	[M€]	Annuitized overnight cost of storage unit *ees*
MB_{ees}	[M€]	Annuitized *ees* mothballing cost

$O\&M_{ees,t}$	[M€]	Operation and maintenance cost of *ees* units
S_{ees}^{ini}	[GW]	Initial installed power capacity of storage technology *ees*
S_{ees}^{inv}	[GW]	New power capacity investments of storage technology *ees*
S_{ees}^{MB}	[GW]	Mothballed power capacity of storage technology *ees*
E_{ees}^{ini}	[GW]	Initial installed energy capacity of storage technology *ees*
E_{ees}^{inv}	[GW]	New power energy investments of storage technology *ees*
E_{ees}^{MB}	[GW]	Mothballed energy capacity of storage technology *ees*
$S_{ees,t}^{ch}$	[GW]	Power demand by storage unit *ees* on time t
$S_{ees,t}^{dch}$	[GW]	Power supply by storage unit *ees* on time t
$S_{ees,t}^{ch+}$	[GW/h]	Demand increase of storage unit *ees* in hour *t* while charging
$S_{ees,t}^{ch-}$	[GW/h]	Supply increase of storage unit *ees* in hour *t* while charging
$S_{ees,t}^{dch+}$	[GW/h]	Demand increase of storage unit *ees* in hour *t* while discharging
$S_{ees,t}^{dch-}$	[GW/h]	Supply increase of storage unit *ees* in hour *t* while discharging
$E^{l}{}_{ees,t}$	[GW]	Storage level of technology ees
$DSM_{lc,t}$	[GW]	Hourly cost of DSM for load curtailment
$DSM^{l}{}_{lc,t}$	[GW]	DSM curtailment of load *lc* on time t
$DSM_{ls,t}$	[GW]	Hourly cost of DSM for load Shifting
$DSM_{ls,t}^{up}$	[GW]	DSM shifting up *ls* on time t
$DSM_{ls,t,tt}^{do}$	[GW]	DSM shifting up *ls* on time *tt* from *t*
NL_t	[GW]	Net load on time t
LL_t	[GW]	Loss of load on time t
$G_{con,t}^{aFRR_{up}}$	[GW]	Contribution of *con* units to *mFRR* up supply
$G_{con,t}^{aFRR_{do}}$	[GW]	Contribution of *con* unit to *aFRR* down supply

$G_{con,t}^{mFRR_{up}^{sp}}$	[GW]	Contribution of spinning *con* unit to $mFRR$ up supply
$G_{con,t}^{mFRR_{do}^{sp}}$	[GW]	Contribution of spinning *con* unit to $mFRR$ down supply
$G_{con,t}^{mFRR_{up}^{nsp}}$	[GW]	Contribution of non-spinning *con* unit to $mFRR$ up supply
$S_{ees,t}^{ch,aFRR_{up}}$	[GW]	Contribution of *ees* unit to $aFRR$ up supply while charging
$S_{ees,t}^{ch,mFRR_{up}}$	[GW]	Contribution of *ees* unit to $mFRR$ up supply while charging
$S_{ees,t}^{ch,aFRR_{do}}$	[GW]	Contribution of *ees* unit to $aFRR$ down supply while charging
$S_{ees,t}^{ch,mFRR_{do}}$	[GW]	Contribution of *ees* unit to $mFRR$ down supply while charging
$S_{ees,t}^{dch,aFRR_{up}}$	[GW]	Contribution of *ees* unit to $aFRR$ up supply while discharging
$S_{ees,t}^{dch,mFRR_{up}}$	[GW]	Contribution of *ees* unit to $mFRR$ up supply while discharging
$S_{ees,t}^{dch,aFRR_{do}}$	[GW]	Contribution of *ees* unit to $aFRR$ down supply while discharging
$S_{ees,t}^{dch,mFRR_{do}}$	[GW]	Contribution of *ees* unit to $mFRR$ down supply while discharging
$Q_t^{aFRR_{up}}$	[GW]	Total *aFRR* up required on time *t*
$Q_t^{aFRR_{do}}$	[GW]	Total *aFRR* down required on time *t*
$Q_t^{mFRR_{up}}$	[GW]	Total *mFRR* up required on time *t*
$Q_t^{mFRR_{do}}$	[GW]	Total *mFRR* down required on time *t*

Table 20 – List of variables

Equations of the DIFLEXO model used on the calculations:

$$\begin{aligned} Y = & \sum_{con}(I_{con} + MB_{con}) + \sum_{con}\sum_{t}\left(F_{con,t} + O\&M_{con,t} + CO2_{con,t} + \Delta G_{con,t}\right) \\ & + \sum_{vre}(I_{vre} + MB_{vre}) + \sum_{res}\sum_{t}\left(O\&M_{vre,t} + VREC_{vre,t}\right) \\ & + \sum_{ees}(I_{ees} + MB_{ees}) + \sum_{ees}\sum_{t}\left(O\&M_{ees,t} + CO2_{ees,t}\right) \\ & + \sum_{DSM} I_{DSM} + \sum_{lc}\sum_{t} O\&M_{lc,t}^{DSM} + \sum_{ls}\sum_{t} O\&M_{ls,t}^{DSM} \end{aligned} \quad (1)$$

Cost related equations:

$$I_i = crf_i\, P_i^{inv} \qquad \forall\, i \neq ees \quad (2)$$

$$crf_i = \frac{WACC_i\, C_i^{Capital}}{1 - (\frac{1}{1 + WACC_i})^{a_i^{life}}} \qquad \forall\, i \quad (3)$$

$$I_{ees} = crf^S{}_{ees}\, S_{ees}^{inv} + crf^E{}_{ees} E_{ees}^{inv} \qquad \forall\ ees \quad (4)$$

$$S_{ees}\underline{\phi_{ees}} \leq E_{ees} \leq S_{ees}\overline{\phi_{ees}} \qquad \forall\ ees \quad (5)$$

$$I_{DSM} = crf_{DSM}\ DSM \qquad \forall\ ees \quad (6)$$

$$MB_i = 0.05\, C_i^{Capital} P_i^{MB} \qquad \forall\ i \quad (7)$$

$$F_{con,t} = Fuel_{con,t}\, fc_{con} \qquad \forall\ con \quad (8)$$

$$O\&M_{i,t} = o\&m^v{}_i\ G^l{}_{con,t} + o\&m^f{}_i\, P_i \qquad \forall\ i \quad (9)$$

$$CO2_{con,t} = C^{CO2}\ ef_{con}\, Fuel_{con,t} \qquad \forall\ con \quad (10)$$

$$\Delta G_{con,t} = \left| G^{l}{}_{con,t} - G^{l}{}_{con,t-1} \right| lf_{con} \qquad \forall\ con \qquad (11)$$

$$MB_{ees} = 0.05\left(C_{ees}^{Capital,S}\ S_{ees}^{MB} + C_{ees}^{Capital,P} E_{ees}^{MB}\right) \qquad \forall\ ees \qquad (12)$$

$$O\&M_{ees,t} = o\&m^{v}{}_{ees}\left(S_{ees,t}^{ch} + S_{ees,t}^{dch}\right) + \sigma_{ees}\, S_{ees,t}^{dch}\, fc_{ees} + o\&m^{f}{}_{ees}\, S_{ees} \qquad \forall\ ees, t \qquad (13)$$

$$CO2_{ees,t} = C^{CO2}\ ef_{ees}\, \sigma_{ees}\, S_{ees,t}^{dch} \qquad \forall\ ees, t \qquad (14)$$

$$REC_{vre,t} = G_{vre,t}^{cu}\, rec_{vre} \qquad \forall\ vre \qquad (15)$$

$$Fuel_{con,t} = G^{l}{}_{con,t}\, m_{con} + b_{con} \qquad \forall\ con \qquad (16)$$

$$m_{con} = \frac{\Delta FC_{con}^{max}}{\Delta P_{con}^{max}} = \frac{\dfrac{P_{con}\,\overline{p_{con}}}{\overline{\eta_{con}}} - \dfrac{P_{con}\,\underline{p_{con}}}{\underline{\eta_{con}}}}{P_{con}\,\overline{p_{con}} - P_{con}\,\underline{p_{con}}} = \frac{\dfrac{\overline{p_{con}}}{\overline{\eta_{con}}} - \dfrac{\underline{p_{con}}}{\underline{\eta_{con}}}}{\left(\overline{p_{con}} - \underline{p_{con}}\right)} \qquad \forall\ con \qquad (17)$$

$$b_{con} = \left(\frac{\overline{p_{con}}}{\overline{\eta_{con}}} - m_{con}\,\overline{p_{con}}\right) P_{con} \qquad \forall\ con \qquad (18)$$

$$Fuel_{con,t} = \left(G^{l}{}_{con,t} - \overline{p_{con}}\, P_{con}\right) m_{con} + P_{con}\frac{\overline{p_{con}}}{\overline{\eta_{con}}} \qquad \forall\ con \qquad (19)$$

$$O\&M_{lc,t}^{DSM} = DSM^{l}{}_{lc,t}\, o\&m_{lc} \qquad \forall\ t, lc \qquad (20)$$

$$O\&M_{ls,t}^{DSM} = DSM_{ls,t}^{up}\ o\&m_{ls} \qquad \forall\ t, ls \qquad (21)$$

$$G^{l}{}_{vre,t} = \frac{G^{l}{}_{vre,t}^{\ base}}{P_{vre}^{\ base}}\ \left(P_{vre}^{ini} + P_{vre}^{inv} - P_{vre}^{MB}\right) \qquad \forall\ vre, t \qquad (22)$$

EOM market equilibrium:

$$NL_t = L_t^{base}\,(1+\delta) - \sum_{vre}\left(G_{vre,t}^{l} - G_{vre,t}^{cu}\right) \qquad \forall\, t \qquad (23)$$

$$NL_t = \sum_{con} G^{l}{}_{con,t} + \sum_{ees}\left(S_{ees,t}^{dch} - S_{ees,t}^{ch}\right) + \sum_{lc} DSM^{l}{}_{lc,t} + \sum_{ls}\sum_{tt=t-L_{ls}}^{tt=t+L_{ls}} DSM_{ls,tt,t}^{do} - \sum_{ls} DSM_{ls,t}^{up} \qquad \forall\, t \qquad (24)$$

FRR market equilibrium:

$$Q_t^{aFRR_{up}} = \varepsilon_l^{aFRR_{up}}\, L_t^{base}\,(1+\delta) + \sum_{vre} \varepsilon_{vre}^{aFRR_{up}}\, P_{vre} \qquad \forall\, t \qquad (25)$$

$$Q_t^{aFRR_{do}} = \varepsilon_l^{aFRR_{do}}\, L_t^{base}\,(1+\delta) + \sum_{vre} \varepsilon_{vre}^{aFRR_{do}}\, P_{vre} \qquad \forall\, t \qquad (26)$$

$$Q_t^{mFRR_{up}} = \varepsilon_l^{mFRR_{up}}\, L_t^{base}\,(1+\delta) + \sum_{vre} \varepsilon_{vre}^{mFRR_{up}}\, P_{vre} \qquad \forall\, t \qquad (27)$$

$$Q_t^{mFRR_{do}} = \varepsilon_l^{mFRR_{do}}\, L_t^{base}\,(1+\delta) + \sum_{vre} \varepsilon_{vre}^{mFRR_{do}}\, P_{vre} \qquad \forall\, t \qquad (28)$$

$$\sum_{con} G_{con,t}^{aFRR_{up}} + \sum_{ees}\left(S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{dch,aFRR_{up}}\right) = Q_t^{aFRR_{up}} \qquad \forall\, t \qquad (29)$$

$$\sum_{con} G_{con,t}^{aFRR_{do}} + \sum_{ees}\left(S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{dch,aFRR_{do}}\right) = Q_t^{aFRR_{do}} \qquad \forall\, t \qquad (30)$$

$$\sum_{con}\left(G_{con,t}^{mFRR_{up}^{sp}} + G_{con,t}^{mFRR_{up}^{nsp}}\right) + \sum_{ees}\left(S_{ees,t}^{ch,mFRR_{up}} + S_{ees,t}^{dch,mFRR_{up}}\right) = Q_t^{mFRR_{up}} \qquad \forall\, t \qquad (31)$$

$$\sum_{con} G_{con,t}^{mFRR_{do}^{sp}} + \sum_{ees} \left(S_{ees,t}^{ch,mFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \right) = Q_t^{mFRR_{do}} \qquad \forall\, t \tag{32}$$

Capacity market equilibrium (CRM):

$$CA = SA_{req} \left(\max\left(L_t^{base} \, (1+\delta) \right) + L_{Th} \, \Delta T \right) \tag{33}$$

$$CA \leq \sum_{con} P_{con} \, \alpha_{con} + \sum_{ees} S_{ees} \, \alpha_{ees} + \sum_{vre} P_{vre} \, \alpha_{vre} \, cf_{vre} + \sum_{ls,lc} DSM \, \alpha_{dsm} \tag{34}$$

Operating constraints of conventional technologies:

$$P_{con} = P_{con}^{ini} + P_{con}^{inv} - P_{con}^{MB} \qquad \forall\, con \tag{35}$$

$$G^{l}{}_{con,t} + G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}} \leq \overline{p_{con}} P_{con} \qquad \forall\, con, t \tag{36}$$

$$\underline{p_{con}} P_{con} \leq G^{l}{}_{con,t} - G_{con,t}^{aFRR_{up}} - G_{con,t}^{mFRR_{up}^{sp}} \qquad \forall\, con, t \qquad \forall\, con, t \tag{37}$$

$$\Delta G^{l}{}_{con,t} + G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}} \leq G_{con,t}^{+} \qquad \forall\, con, t \qquad \forall\, con, t \tag{38}$$

$$-G^{-}{}_{con,t} \leq \Delta G^{l}{}_{con,t} + G_{con,t}^{aFRR_{up}} + G_{con,t}^{mFRR_{up}^{sp}} \qquad \forall\, con, t \qquad \forall\, con, t \tag{39}$$

$$H2O_w^l = \frac{H2O_w^{avg}}{\overline{P_{hydro}}}\, P_{hydro} + \frac{H2O_w^{inflow}}{\overline{P_{hydro}}} P_{hydro} - \sum_{t \in w} Fuel_{hydro,t} \qquad if \quad w = 1 \qquad (40)$$

$$H2O_w^l - H2O_{w-1}^l = \frac{H2O_w^{inflow}}{\overline{P_{hydro}}} P_{hydro} - \sum_{t \in w} Fuel_{hydro,t} \qquad if \quad w > 1 \qquad (41)$$

$$\underline{H2O} < H2O_w^l \leq \overline{H2O} \qquad \forall\ w \qquad (42)$$

EES related constraints:

$$E_{ees} = E_{ees}^{ini} + E_{ees}^{ini} - E_{ees}^{MB} \qquad \forall\ ees \qquad (43)$$

$$S_{ees} = S_{ees}^{ini} + S_{ees}^{ini} - S_{ees}^{MB} \qquad \forall\ ees \qquad (44)$$

$$E^l{}_{ees,t} = E^l{}_{ees,t-1}\,(1 - sd_{ees}) + \left(\sqrt{\eta_{ees}}\ S_{ees,t}^{ch,} - \frac{S_{ees,t}^{dch}}{\sqrt{\eta_{ees}}}\right) t_{slice} \qquad \forall\ t,\ ees \qquad (45)$$

$$\underline{e_{ees}}\, E_{ees} \leq E^l{}_{ees,t} \leq \overline{e_{ees}}\, E_{ees} \qquad \forall\ t,\ ees \qquad (46)$$

$$S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees}\ \overline{s_{ees}}^{ch} - S_{ees,t}^{ch} \qquad \forall\ t,\ ees \qquad (47)$$

$$S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{ch,mFRR_{do}} \leq S_{ees,t}^{ch} \qquad \forall\ t,\ ees \qquad (48)$$

$$S_{ees,t}^{dch,aFRR_{up}} + S_{ees,t}^{dch,mFRR_{up}} \leq S_{ees,t}^{dch} \qquad \forall\ t,\ ees \qquad (49)$$

$$S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees}\ \overline{s_{ees}}^{dch} - S_{ees,t}^{dch} \qquad \forall\ t,\ ees \qquad (50)$$

$$S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees}\ \overline{s_{ees}}^{dch} \qquad \forall\ t,\ ees \qquad (51)$$

$$S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees}\ \overline{s_{ees}}^{ch} \qquad \forall\ t,\ ees \qquad (52)$$

$$\Delta S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees,t}^{ch+} \qquad \forall\ t,\ ees \qquad (53)$$

$$-S_{ees,t}^{ch-} \leq \Delta S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{ch,mFRR_{do}} \qquad \forall\ t,\ ees \qquad (54)$$

$$\Delta S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees,t}^{dch+} \qquad \forall\ t,\ ees \qquad (55)$$

$$-S_{ees,t}^{dch-} \leq \Delta S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \qquad \forall\ t,\ ees \qquad (56)$$

$$S_{ees,t}^{ch+} = r_{ees}^{ch+}\ S_{ees}\ 60\ t_{slice} \qquad \forall\ t,\ ees \qquad (57)$$

$$S_{ees,t}^{dch+} = r_{ees}^{dch+}\ S_{ees}\ 60\ t_{slice} \qquad \forall\ t,\ ees \qquad (58)$$

$$S_{ees,t}^{ch-} = r_{ees}^{ch-}\ S_{ees}\ 60\ t_{slice} \qquad \forall\ t,\ ees \qquad (59)$$

$$S_{ees,t}^{dch-} = r_{ees}^{dch-}\ S_{ees}\ 60\ t_{slice} \qquad \forall\ t,\ ees \qquad (60)$$

$$\left(S_{ees,t}^{ch}\ t_{slice}\right)\sqrt{\eta_{ees}} \leq E_{ees} - E^{l}{}_{ees,t-1} \qquad \forall\ t,\ ees \qquad (61)$$

$$\frac{S_{ees,t}^{dch}\ t_{slice}}{\sqrt{\eta_{ees}}} \leq E^{l}{}_{ees,t-1} \qquad \forall\ t,\ ees \qquad (62)$$

$$\left[S_{ees,t}^{ch}\ t_{slice} + S_{ees,t}^{ch,aFRR_{do}}\ t_{aFRR} + S_{ees,t}^{ch,mFRR_{do}}\ t_{mFRR}\right]\sqrt{\eta_{ees}} \leq E_{ees} - E^{l}{}_{ees,t} \qquad \forall\ t,\ ees \qquad (63)$$

$$\left[S_{ees,t}^{dch}\ t_{slice} + S_{ees,t}^{dch,aFRR_{up}}\ t_{aFRR} + S_{ees,t}^{dch,mFRR_{up}}\ t_{mFRR}\right]\frac{1}{\sqrt{\eta_{ees}}} \leq E^{l}{}_{ees,t} \qquad \forall\ t,\ ees \qquad (64)$$

DSM related constraints:

$$0 \leq DSM^{l}{}_{lc,t} \leq \overline{dsm}_{lc}\ L_t^{base}\ (1+\delta) \qquad \forall\ t, lc \tag{65}$$

$$\sum_{tt=0}^{R-1} DSM^{l}{}_{lc,t+tt} \leq \overline{dsm}_{lc}\ L_t^{base}\ (1+\delta)\ L_{lc} \qquad \forall\ t, lc \qquad \forall\ t, lc \tag{66}$$

$$DSM_{ls,t}^{up} = \sum_{tt=t-L_{ls}}^{t+L_{ls}} DSM_{ls,t,tt}^{do} \qquad \forall\ t, ls \tag{67}$$

$$DSM_{ls,t}^{up} \leq \overline{dsm}_{ls}^{up}\ L_t^{base}\ (1+\delta) \qquad \forall\ t, ls \tag{68}$$

$$DSM_{ls,t}^{up} + \sum_{tt=t-L_{ls}}^{tt=t+L_{ls}} DSM_{ls,t,tt}^{do} \leq max\left(\overline{dsm}_{ls}^{up}; \overline{dsm}_{ls}^{do}\right) L_t^{base}\ (1+\delta) \qquad \forall\ t, ls \tag{69}$$

$$DSM^{l}{}_{lc,t} + DSM_{ls,t}^{up} + \sum_{tt=t-L_{ls}}^{tt=t+L_{ls}} DSM_{ls,t,tt}^{do} \leq DSM \qquad \forall\ t, lc, ls \tag{70}$$

Energy policy constraints:

VRE shares:

$$\sum_{t} \sum_{con \neq hydro} G_{con,t}^{l} \leq \left(\frac{1-\theta_{vre}}{\theta_{vre}}\right)\left[\sum_{t}\sum_{vre} (G^{l}{}_{vre,t} - G_{vre,t}^{cu}) + \sum_{t} G^{l}{}_{hydro,t}\right] \tag{71}$$

Nuclear moratorium:

$$\sum_{t} G^{l}_{nuclear,t} \leq \left(\frac{1-\theta_{con}}{\theta_{con}}\right)\left[\sum_{t}\sum_{vre}\left(G^{l}{}_{vre,t} - G^{cu}_{vre,t}\right) + \sum_{t}\sum_{con\neq nuclear} G^{l}_{con,t}\right] \quad \begin{matrix} if \\ con = nuclear \end{matrix} \qquad (72)$$

$$P^{inv}_{con} = P^{MB}_{con} \quad \begin{matrix} if \\ con = nuclear \end{matrix} \qquad (73)$$

B. TECHNICAL PARAMETERS OF STORAGE TECHNOLOGIES

Technology	EES_Emin [%]	Chg_ramp [% S/h]	Dchg_ramp [% S/h]	Auth_min [h]	Auth_max [h]	Self_dch [% E/h]	Efficiency [%]	Derating factor
Li-ion	20%	100%	100%	1	3	0,0167%	90%	86%
NaS	10%	100%	100%	1	7	0,8333%	83%	86%
VRFB	10%	100%	100%	1	8	0,0004%	78%	86%
PHS	10%	100%	100%	1	8	0,0000%	76%	54%
DCAES	15%	100%	100%	1	6	0,0004%	90%	54%
Flywheel	-	100%	100%	1	1,5	4,1667%	94%	
Lead_acid	20%	100%	100%	1	3	0,0083%	80%	86%
ACAES	20%	100%	100%	1	12	0,0004%	90%	54%

C. TECHNICAL PARAMETERS OF GENERATION TECHNOLOGIES

Technology	*Efficiency*	*pmin* [%]	*pmax* [%]	*ramp_up* [per min]	*ramp_down* [per min]	*reg_up* [%]	*reg_down* [%]	*spin_rsv* [%]	*eff_loss*	*m_eff*	*Derating factor*
Nuclear	32%	0,5	1	5%	5%	0,025	0,025	0,75	*0,24*	2,30	0,84
Hard coal	47%	0,4	1	4%	6%	0,020	0,030	0,6	*0,06*	1,95	0,87
CCGT	62%	0,3	1	8%	8%	0,040	0,040	1,2	*0,072*	1,95	0,88
OCOT	34%	-	1	25%	25%	0,125	0,125	3,75	*0,013*	2,94	0,94
OCGT	39%	-	1	10%	10%	0,050	0,050	1,5	*0,06*	2,56	0,94
Reservoir	90%	-	1	20%	20%	0,100	0,100	3	-	1,11	0,86

Note: As in (Brouwer et al. 2016)**, the 'triangular ramping rule' analogy was used to simulate the inability of thermal units to sustain the per minute ramping rates during the course of the hour. Therefore, only 33% of the "per minute" rate is effectively available.**

D. ESTIMATIONS OF THE POTENTIAL SITES FOR ENERGY STORAGE IN FRANCE

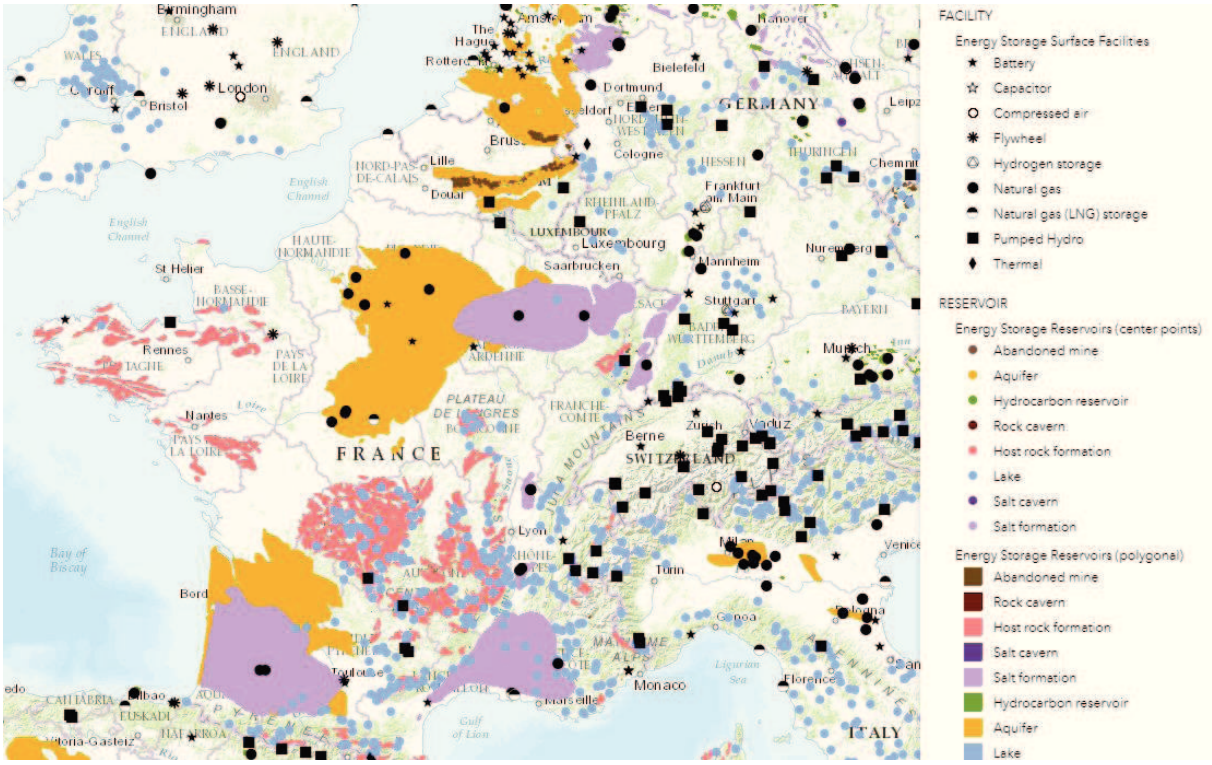


Figure 36. Geographic distribution of potential energy storage reservoirs and locations of known energy storage facilities. Source: (ESTMAP 2017)[80]

[80] For further information visit the ESTMAP project's webpage:

http://tno.maps.arcgis.com/apps/webappviewer/index.html?id=937305e2273847e0bc16503990f79d77

CHAPTER III

PROPER PLANNING AND POLICIES PREVENT POOR PERFORMANCE ON POWER SYSTEMS TOO:

ON THE LONG-TERM GOVERNANCE OF THE FRENCH ENERGY TRANSITION

"A study of the history of opinion is a necessary preliminary to the emancipation of the mind"

John Maynard Keynes

CONTENTS OF CHAPTER III

3.1. INTRODUCTION

Since the early studies establishing the fundamentals long-term energy (Bessiere 1970; Criqui 2001; Grubb 1991; Martin and Diesendorf 1983; Rahman and Bouzguenda 1994), through more refined studies with more comprehensive methodologies (Bouffard and Galiana 2008; Budischak et al. 2013; Carrión and Arroyo 2006; DeCarolis and Keith 2006; Green and Vasilakos 2011; Haller, Ludig, and Bauer 2012; De Jonghe, Hobbs, and Belmans 2012; Lund 2006), until recent developments combining cutting-edge simulation tools and up-to-date data (Brouwer et al. 2016; Després et al. 2017; Eriksen et al. 2017; Hirth 2015; Lorenz 2017; Palmintier 2013; Poncelet, Delarue, et al. 2014; Stiphout 2017; Teng et al. 2015), power system planning have been a fervent research field, whose accuracy has become quite redoubtable. It is an open field that is continuously fed by the political and economic context of the time, but also, by societal and environmental concerns. It has proven to be extremely valuable for providing guidelines to decision makers on energy policy affairs.

Proper planning seems particularly relevant on the current context where power systems are rapidly evolving due to carbon emission concerns, the rebirth of energy security distresses dealing with security of supply, and technological breakthroughs.

Most of recent studies on power system planning have been focused on prospection efforts for assessing arbitrary goals over divers' time horizons. These goals use to be set by a policy-making authority[81] (e.g., a renewable portfolio standard, an exogenous carbon tax level, or other similar technological-push objective), or correspond to a major, rather idealistic, objective (e.g., 100% renewable energy shares or a zero emission system) (Armaroli and Balzani 2011; Delucchi and Jacobson 2011; Hohmeyer and Sönke 2014; Jacobson and Delucchi 2011). Hence, such developments offer appropriate pathways for attaining such goals in the most efficient manner. Yet, few of them interrogate the main economic rationale of such objectives. Most of them fail on putting in perspective such goals against the least-cost system that would be obtained if no technological push would have been enforced.

[81] On this class we can find most of the state's official energy roadmaps. For instance, Australia and Hawaii have recently launched their roadmaps for the transformation of their power systems to 100% renewables by 2050 and 2040 respectively. Further information can be found in the webpage of those studies:

Australian roadmap: http://www.energynetworks.com.au/roadmap-final-report

Hawaiian roadmap: https://www.hawaiianelectric.com/about-us/our-vision

In point of fact, adding such a supplementary figure would be futile if the objective is to elaborate a roadmap for policy implementation, or to evaluate the technical feasibility of those arbitrary goals. In most of the cases, power system planning only assesses previously defined objectives, but not inquiry on the main rationale of such objectives. However, putting them in perspective would be useful for guiding a better-informed decision process. This, at least, would provide more detailed information about the complete costs related to the manifold policy choices. Addressing the planning question with a larger economic reasoning would add deeper insights on the issue itself.

In the absence of such economic insights, policy implications may lack a dimension needed to properly evaluate the whole picture. Moreover, the findings may fail on revealing the cost-efficiency of such policy recommendations. Recent studies considering the entire power system to be composed only by renewable energy sources (Jacobson, Delucchi, Bazouin, et al. 2015; Jacobson, Delucchi, Cameron, et al. 2015) have received particular attention from the research community. They have introduced a matter of clash between analyst (Clack et al. 2017) that advocate for preserving a transparent and non-partisan energy policy debate [82].

On the other hand, the main energy economic question should not be whether it is technically possible, desirable, or even appropriate in a moral fashion, to consider an energy mix exclusively composed by one or another specific technology. Those are questions that should be apprehended from other fields to enlarge the debate. A suitable approach from energy economics would come from reformulating the question, and in turn enquiring: what would be the better combination of technologies, considering current and expected technologic progress, allowing for operating a system with limited CO_2 emission levels and at least-cost? It is to be noted that this different question does not exclude the possibility of obtaining an outcome containing only a unique technology, or a restraint set of them, but it unequivocally broader the analysis.

Even in the case where the focus would be on studying a fully renewable energy scenario, the relevant economic question should deal with the affordability of such case, so answering

[82]This issue has been summarized by the MIT technology reviews electronic journal: https://www.technologyreview.com/s/608126/in-sharp-rebuttal-scientists-squash-hopes-for-100-percent-renewables/

the questions on: how much would it cost to attain that goal? And, how expensive would it be when compared with a market-driven system with equivalent carbon footprint?

System planning is the main instrument to inform about possible future outcomes according to current prospects. For proper planning, keeping precision is mandatory, but still, solid economic foundations are also required for accurate policy recommendations. D'haeseleer et Al. (2017) brilliantly exposed:

> *"... policy and regulation often have unexpected and, possibly counterproductive effects on overall system performance. It should, therefore, be a part of good policy making to first study the overall system by modeling its different parts, with much emphasis on the interactions among the different subparts as well as among different policies. As the behavior of the system including the not always predictable behavior of customers and other market actors will be strongly nonlinear, careful analysis is called for, well beyond the standard isolated "impact assessments."*

Therefore, it is to be said that proper planning should be a prerequisite for policymaking. Likewise, analyst should consider the current policy context from a broader view. The links between environmental and energy policies are often confused, when not disregarded. This is particularly true on current power systems. Furthermore, the interactions of such policies with electricity markets open additional dimensions on the complexity for decision makers. D'haeseleer et Al. (2017) also recognize that "quick-and-dirty regulation will likely backfire, and even simple, positive-seeming measures may lead to unforeseen side effects because of negative feedback and system interactions".

Current policies addressing the power sector are founded in the energy trilemma[83]. The energy trilemma uses to be presented as a challenge, so solutions for balancing the three factors should be found. Even if this view might be positive for enhancing technological development and innovation, this perspective needs to be enlarged from an energy economics interpretation. In economics, the energy trilemma should be understood as belonging to the same family of the well-known Mundell-Fleming trilemma or "impossible

[83] The energy trilemma is the main definition of energy sustainability. It has been coined by the World Energy Council as satisfying the three core dimensions: energy security, energy equity, and environmental sustainability. Further details on this point can be found in: https://www.worldenergy.org/work-programme/strategic-insight/assessment-of-energy-climate-change-policy/

trinity"[84]. Hence, what is often forgotten by policymakers and analyst is this inherent nature of a trilemma, which is the impossibility of fully satisfying the three goals simultaneously, so, requiring complex policy trade-offs.

This is particularly pertinent on the energy sector, where several low-carbon emission technologies exist and experience continuous progress (e.g., nuclear power technologies) or are expected to become feasible in the near term (e.g., carbon capture and storage), but also, where the enforcement of technology-specific targets can result in higher abatement costs than applying carbon reduction policies in other sectors of the economy.

Yet, factors like the important cost reductions of renewable energies, the unparalleled perspectives of smart grid solutions, and the promising learning rates experienced by new storage technologies, explicitly portray a transformation path towards cleaner and smarter power systems. Proper planning for policy-making should closely track this transformation path and enable further developments trough proper incentives. Any other approach may lead to inefficient allocations and/or poor performance.

This chapter sheds light on the multiple factors affecting the evolution of current power systems. It is particularly focused on analyzing the need and impact of policy intervention given the technological prospects expected by 2050. Thus, the role of smart grid solutions and electric energy storage (EES) technologies are described, and advanced conventional technologies are outlined. Then, a quantitative study of the French case towards the 2050 horizon is proposed. The findings give relevant policy implications for the governance of the energy transition and effectiveness of the decarbonization goals.

The present chapter is organized as follows: Section 0 present a non-comprehensive but detailed description of the several aspects shaping future power systems. It gives relevant insights on the key game changers currently evolving in the electricity industry. Section 3.3 introduces the most relevant modeling issues required for comprehensively assessing the short-run and long-run interactions while planning capacity investments. It presents the enhancements of the DIFLEXO model to represent scenarios after 2030, where new capabilities on the demand-side are enabled due to widely spread implementation of "smart grids". Hence, this section describes the representation of demand-side flexibility, which evolves from a monolithic concept to a categorical representation of multiple categories of

[84] The Mundell-Fleming argues that it is not possible for a country to have simultaneously a fixed exchange rate, monetary autonomy and the free flow of capital.

demand-response (DR). Using an enhanced representation of the demand-side flexibility with a detailed representation of storage technologies, section 0 proposes a detailed quantitative analysis of the French case towards 2050. The official goals involving a profound decarbonization process while achieving ambitious energy transition objectives are evaluated. The need necessary policies for achieving those goals are assessed, and their associated costs are estimated. The final section presents a discussion of the findings considering the importance of sound energy policies and flexibility support to foster the cost-efficient transformation of the power system.

3.2. TECHNOLOGICAL PROSPECTS ON THE SCOPE

3.2.1. THE EVOLVING GENERATION TECHNOLOGIES

- **Renewable energy technologies**: recent outlooks of wind and solar energy technologies have shown significant cost reductions due to progress on technology development and mass production, which would further allow fast capacity deployments. Onshore wind energy developments such as bigger wind turbines and enhanced power electronics are expected to continue driving cost reductions at a moderate rate for the next decades, while less mature offshore technologies are expected to experience more important cost reductions due to the development of advanced floating platforms and improvements on technical lifetime. Developments in power electronics and improved forecasting techniques can allow wind capacity to assume balancing responsibilities for the supply-demand equilibrium on the electricity markets and for frequency response. Ahlstrom et al. (2013) state that with current forecasts accuracy, the market operators can dispatch wind infeed within a five-minute timescale[85], thus, improved forecasts and faster gate closures could even allow wind to be dispatchable in the intraday or day-ahead markets in the future.
  Solar photovoltaic technologies have also experienced important progress benefiting from massive deployment, manufacturing escalation, and learning-by-doing. This trend is expected to be sustained in the short-term but moderated in the long-term

[85] Ahlstrom et al. (2013) explain that this 5-minute dispatch of wind has being applied by the New York and the Texas Independent System Operator (NYISO and ERCOT) for balancing reserves. The Midcontinent and the Alberta System operators (MISO and AESO) are studying even more ambitious targets dealing making the wind follow a 10 minute set-point within a tolerance band of 8%.

due to "soft cost" of new facilities[86]. Solar thermal technologies are expected to show more modest cost reductions on the next decades.

Other renewable energy technologies, such as hydropower and geothermal, are more mature but are very site specific. Their costs are expected to be stable, but their relative competitiveness can be enhanced due to the implementation of CO_2 pricing mechanisms. Inversely, ocean energy technologies (i.e., wave and tidal) still show very low technology readiness levels, so cost reductions can be disruptive but are still very difficult to predict (Carlsson 2014).

- **Nuclear technologies**: Third-generation technologies[87] are expected to replace the existing nuclear capacity offering improved security levels, enhanced efficiency, lower fuel usage and more flexible operating capabilities. The first units of those technologies are currently being built, thus, as technology becomes mature, some reductions in cost can be expected on the long-term compared to first-of-a-kind (FOAK) projects. Fourth generation technologies are still out of the scope and are not expected to have commercial maturity before the 2050 horizon (Carlsson 2014).
- **Carbon capture and storage**: It is the group of technologies based on the principle of separating the CO_2 emissions from combustion processes and impeding its dissemination on the atmosphere. CO_2 can be captured by using pre-combustion techniques such as using solid fuel gasification or steam reforming of natural gas, to produce lower carbon-intensive synthesis gas for fueling power units. Post-combustion techniques involve scrubbing[88] the exhaust gas emitted during the combustion process by a purifying stage with solvents, allowing their application to existing fossil fuel plants with negligible modifications. Nevertheless, since these techniques involve a complexification of the regular thermodynamic cycles of conventional fossil units, a cost increase can be expected compared with the former. These technologies still need to prove large-scale technical feasibility, as well as the safeness of storing CO_2 (International Energy Agency, 2014).

[86] Even if the cost of solar panels continues to decline, "Soft costs" of PV are mainly related to installation and permits impose some levies to its deployment.

[87] Light water reactors (LWR).

[88] Among the most common post-combustion techniques studied are membrane filtration and adsorption/desorption processes, among others.

- **Advanced fossil fuels**: Conventional fossil fuel technologies are quite mature technologies showing low intrinsic progress. Nevertheless, different configurations are being conceived allowing for multiple fuel infeed or co-firing, enabling easy fuel switching to biofuels, adding co-generation capabilities to use the heat left over for improving the total efficiency of installations, and by enhancing flexible capabilities to lower the cost of cycling. Fossil fuel plants are also expected to integrate carbon capture and storage technologies when economically feasible (Carlsson 2014).

3.2.2. THE DISRUPTIVE TREND OF STORAGE TECHNOLOGIES

Electric energy storage (EES) technologies are among the main game changers expected in the industry for the next years[89]. Storage can be deployed from grid to customer level and can offer multiple services to the whole system when integrally managed[90] and for the individual owner, particularly when installed behind-the-meter and paired with PV. It is to be highlighted the case of batteries; the important cost declines of battery packs mainly driven by electronics appliances have also allowed for spillovers on power applications, driving down the costs of them as well (see Figure 37). This dynamic is presenting a growing threat to utility's business models, challenging the TSO and DSO coordination schemes, and possibly impacting the retailer's revenues in the near future due to grid defection.

From a technical point of view storage technologies can be classed by the energy conversion process involved, comprising: mechanical energy, consisting of pumped-hydro storage (PHS), compressed air energy storage (CAES) and flywheels; electrochemical energy, consisting of batteries such as Li-ion technologies, advanced lead-acid batteries, among others, but also flow batteries such as Vanadium-Redox (VRB) and Zinc-Bromine (Zn-Br) batteries, and hydrogen (H_2) based technologies combining electrolysers and fuel cells (FC); finally, technologies based on electromagnetic principles such as the superconducting

[89] This is a point that has been growing consensus in the research community but also among the industrials due to the promising cost declines of new storage technologies. Further and recent figures about how storage technologies are currently evolving from niche markets to a scale causing the transformation of the business model of incumbent utilities can be found on the last study from McKinsey and Co, which is available online at the following address:

http://www.mckinsey.com/business-functions/sustainability-and-resource-productivity/our-insights/battery-storage-the-next-disruptive-technology-in-the-power-sector

[90] The value of storage for as entire power system was developed in the previous chapter.

magnetic energy storage (SMES) alternatives are also being considered (Kempener and Borden 2015; Luo et al. 2015; Palizban and Kauhaniemi 2016).

Currently, the most mature and widespread EES technology is PHS. Nevertheless, technologies like Li-ion batteries, CAES and H_2-FC have experienced important technical progress and are expected to entail similar cost reduction trends on the next years than photovoltaic technologies have done during the last decade. Furthermore, there is a growing consensus in the research community that even with expected high capital costs, EES can supply multiple services to the system in a manner that they could stack different sources of value making them break-even (World Energy Council 2016).

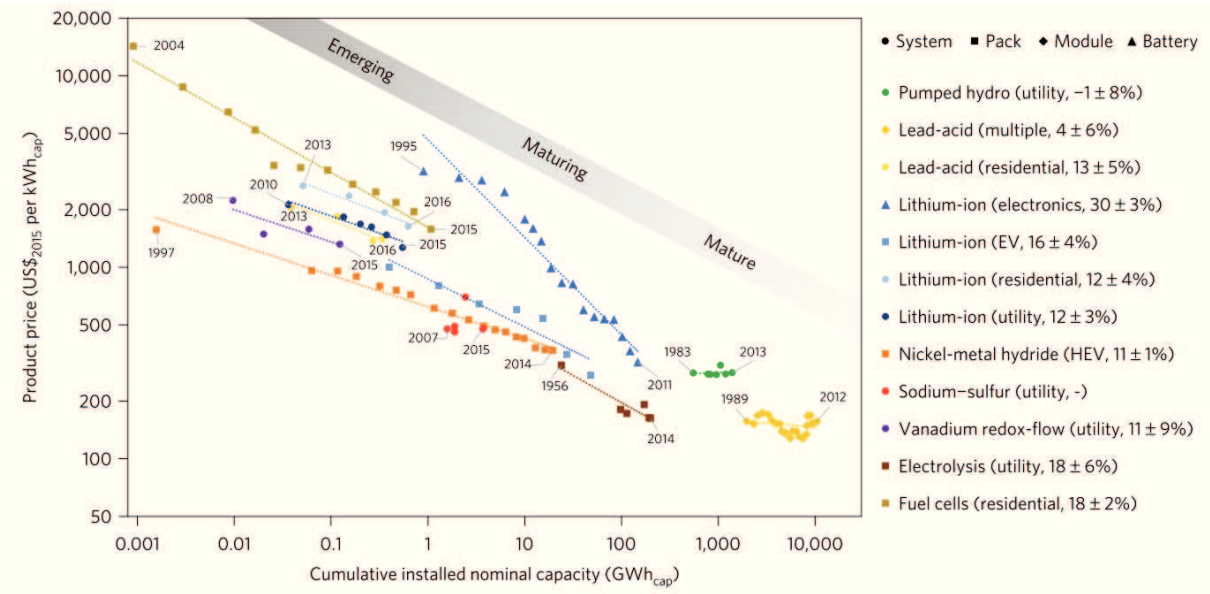


Figure 37. Learning curves of some EES technologies. Source: (Schmidt et al. 2017)

From a practical viewpoint, EES technologies can be classified by the length of the charge-discharge cycle they can feasibly withstand. Thus, the short-term storage corresponds to small cycling periods ranging from seconds to hours, and the long-term storage ranges from hours to weeks. Also, their capabilities to follow-up a control signal for frequency regulation, so, slow and fast technologies. The scale of the facility and their sitting are also important parameters differentiating the EES technologies on categories like bulk, distributed, or even behind-the-meter storage applications (Fitzgerald et al. 2015).

EES costs are mainly related to technical features and project scale, but practical characteristics define the kind of service they are capable to supply, thus, assessing the value EES on an integrated power system must combine both dimensions of the problem.

3.2.3. DEMAND-SIDE MANAGEMENT AND DEMAND RESPONSE IN THE SMART GRID ENVIRONMENT

Demand-side management (DSM) measures range from specific energy efficiency incentives, to deploying sophisticated load management systems to dynamically control the load (Palensky and Dietrich 2011). Smart grid technologies are expected to enlarge the capabilities to automate load control, thus, will facilitate new strategies for network management.

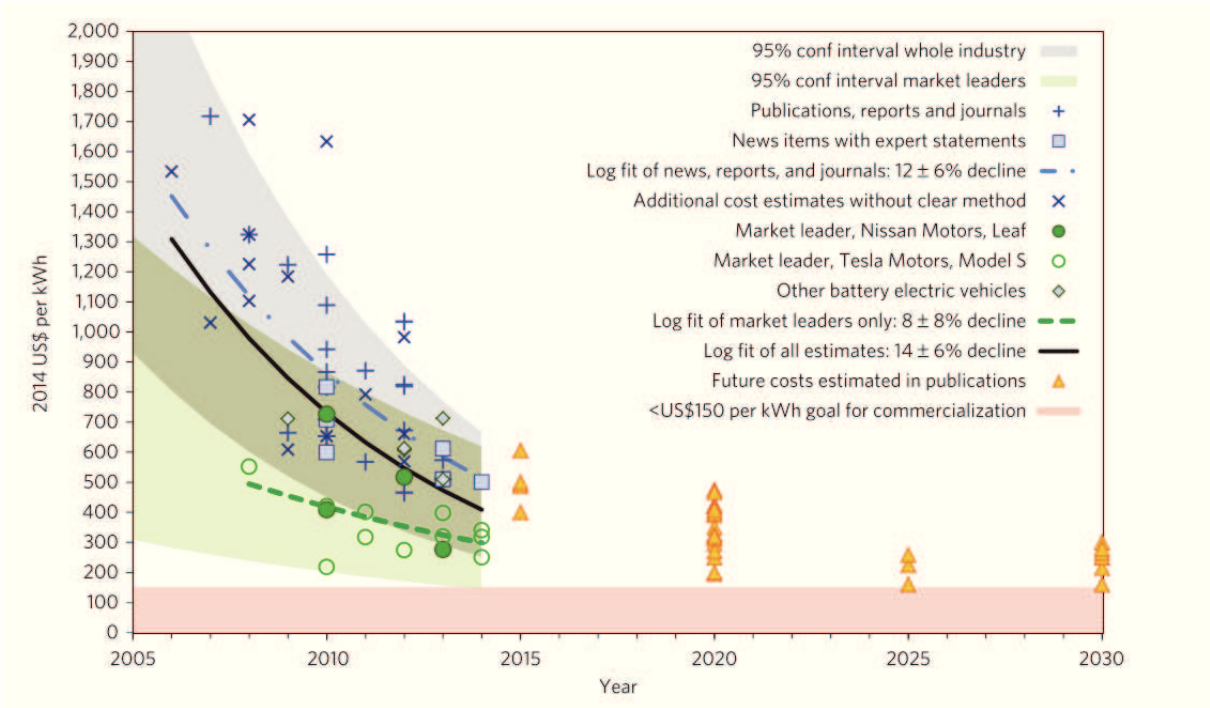
The deployment of advanced metering infrastructure (AMI), together with the uptake of smart appliances, load management systems at the user level, and the increasing electrification of complementary energy use[91] will significantly broaden the DSM capabilities for enabling higher levels of demand-side flexibility. New concepts such as Power–to-X or even sector coupling are emerging to assess the interoperability of supply and demand of different energy services.

At present, the main flexibility of demand comes from managing electricity uses with some energy inertia[92], which allows for some degree of consumption deferral. But, in the mid-future, smart grids would allow key emerging actors, such as the electric vehicles (EV), as well a behind-the-meter storage such as stationary batteries, to play a relevant role in supplying demand-side flexibility. Therefore, DSM capabilities are expected to benefit from the cost decline of complementary technologies as presented Figure 38.

Smart grids will allow new electricity usages to be managed without any loss of well-being for customers across multiple sectors. Heating systems, sanitary hot water, and some industrial processes constitute the more thorough electricity usages which will offer low-cost sources of flexibility. DSM measures are considered as the lower cost solution for enhancing flexibility (Brouwer et al. 2016; RTE 2015). In most of the cases, it is simpler, and cheaper, to use existing demand-side flexibility resources by the implementation of improved control strategies than building new flexibility capacity or developing new technologies.

[91] It is mainly the electrification of ambient heating and cooling and transportation.

[92] Namely, space heating appliances, refrigerated goods, sanitary hot water, and some flexibility in schedules.



Note: The cost of US $150/kWh is commonly considered as the point of commercialization of EV.

Figure 38. Cost of battery packs of EV. Source: (Nykvist and Nilsson 2015)

Demand-side flexibility, supported by the convenient market structures and regulatory frameworks, is expected to enable a enhanced participation of consumers on supplying different types of system services [93]. Recent studies consider important smart grid deployment levels during the next years and estimate their value to range between the 1% [94] and 2%[95] of the total system cost (ADEME 2017; Alstone et al. 2017).

Demand response (DR) is the main kind of demand-side management (DSM) that smart metering would enable. It is defined by the DOE[96] in the following terms:

> *"Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale*

[93] Taking actions such as peak shaving, valley filling, load shifting and reserve supply.

[94] The recent study of (RTE 2017b) assesses the case of France in the 2030 horizon considering a comprehensive set of system needs and technology interactions.

[95] This is one of the main outcomes of Brouwer (2016), who considered the value on the energy only market on the perimeter of the western European countries by 2050.

[96] The US Department of Energy.

market prices or when system reliability is jeopardized" (US Department of Energy, 2006).

DR programs may take the form of market-based programs, by applying dynamic rates to customers in order to provide them with the cost of producing the electricity at the moment of consumption, or can be applied by incentive-based programs, by providing financial incentives (i.e., penalties and/or price rebates) to consumers for changing their consumption patterns during specific moments[97].

Smart metering devices would allow utilities to apply such DR schemes by setting and controlling different types of consumers allowing them to adopt a price-aware behavior. Price-signals provide information of the upcoming state of the power network; thus, consumers can anticipate it and adjust their consumption accordingly[98].

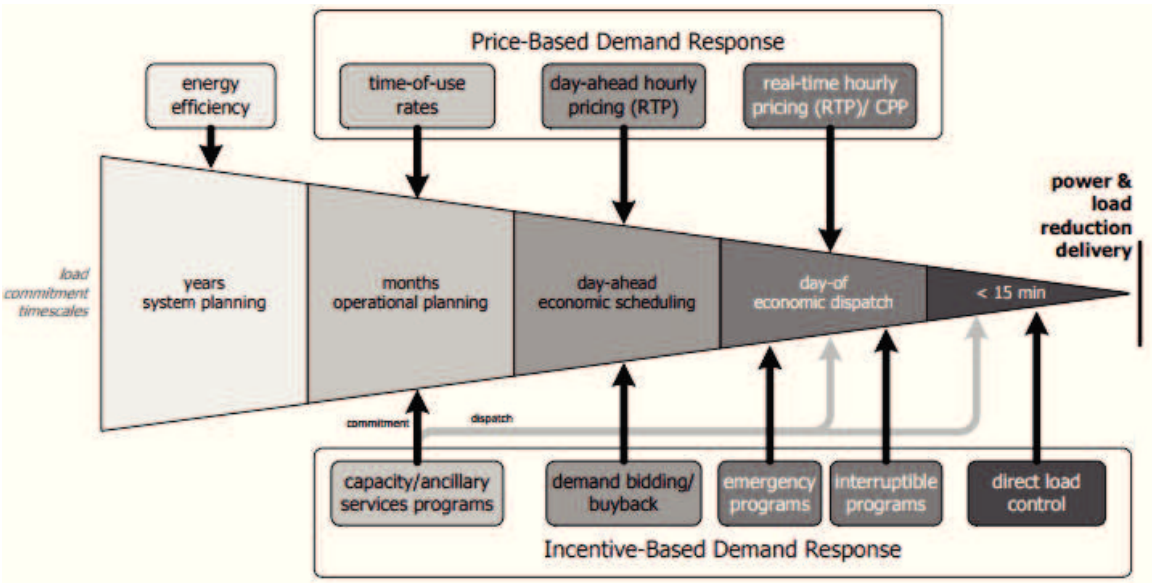


Figure 39. Types of DR programs. Source: (US Department of Energy, 2006)

PRICE-BASED DR PROGRAMS

They are defined by the rate design implemented by the utility. Price-signals can vary as frequently as hourly for the case of real-time pricing or can be set weekly, monthly or

97 A review of the current alternative rate designs being currently applied in the US is presented by the Rocky Mountain Institute: https://www.rmi.org/insights/reports/review-alternative-rate-designs/

98 For further details on dynamic pricing see: (Faruqui et al., 2009; Lazar, 2013; Lazar and Colburn, 2015).

seasonally, considering the regularity of peak and off-peak periods. Some of the dynamic pricing alternatives discussed in the current literature are:

- Time of use (TOU) tariffs: They are tariff schemes where the specified rates are applied over predefined periods of the day. They define at least an off-peak and an on-peak period. More complex variations can include extreme peak periods and vary the time definition along the seasons.

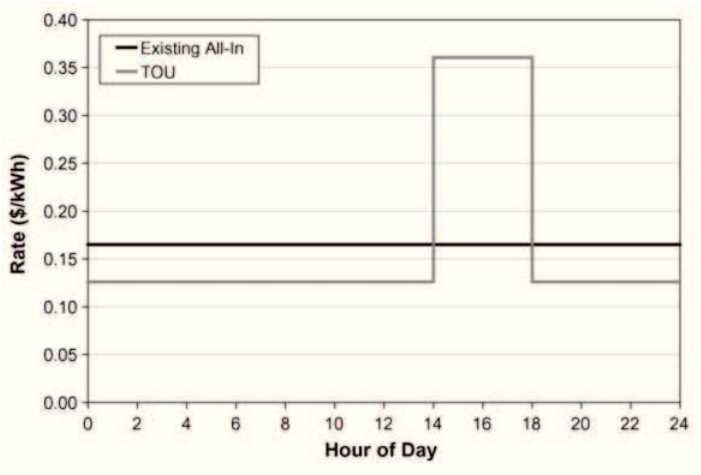


Figure 40. Example of a TOU rate. Source: (Faruqui, Hledik, and Tsoukalis 2009)

- Critical peak-pricing (CPP): It is a rating scheme that differentiates critical and non-critical days in order to send a stronger price signal to consumers. They are used to account for capacity needs during dimensioning days. It particularly focuses on penalizing peak hours of critical days.

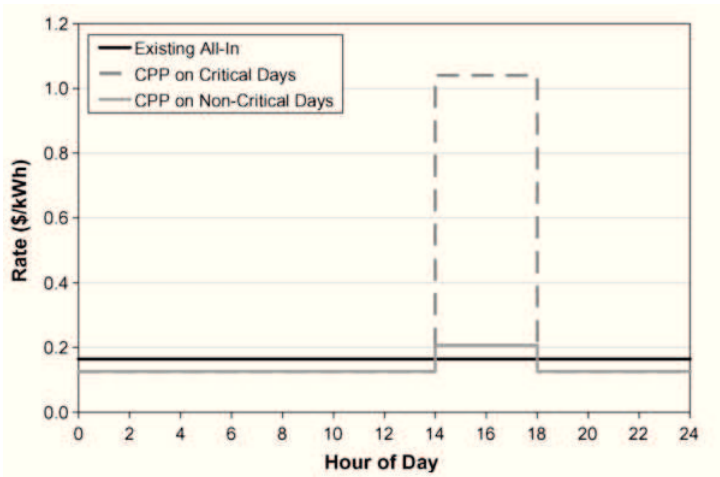


Figure 41. Example of a CPP scheme. Source: (Faruqui et al., 2009)

- Variable peak pricing (VPP): it is a combination of TOU tariff with real-time pricing during peak periods.
- Peak-time rebates (PTR): it is a compensation instrument that works on an incident-by-incident basis during extreme episodes. The compensation is based on a load reduction against a pre-established baseline load. The rates during the year remain fixed and consumers can buy at any moment at this rate, but only receive the compensation if they reduce their load during the specified episode.

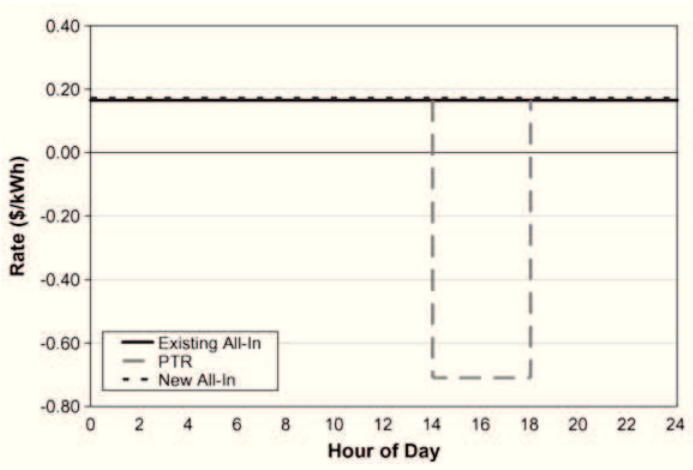


Figure 42. Example of a PTR scheme. Source: (Faruqui et al., 2009)

- Real-time pricing (RTP): It is a scheme on which rates vary on an hourly basis reflecting more accurately the market price of electricity. Customers are provided with price information on the day or hour-ahead, depending on the specifications of the contract.

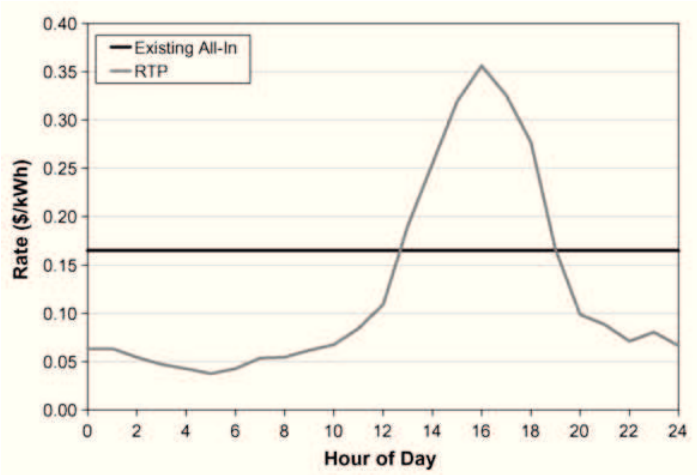


Figure 43. Example of a RTP scheme. Source: (Faruqui et al., 2009)

INCENTIVE-BASED DR PROGRAMS

Incentive-based mechanisms are very broad, comprising demand bidding on the wholesale and/or in the capacity market, or even for reducing consumption during emergency episodes. Among the most promising DR programs enabled by smart meters are:

- The direct control of load: This program accounts for automated demand shifting. This is the capability of rescheduling the demand planned to a different time. Some industrial processes such as heating or cooling, irrigation, pumping, or production schedules, can be shifted before or later an expected critical episode. Such programs can be mainly applied to large customers or through aggregation.
- The interruptible/curtailable (I/C) service: It accounts for load curtailment capabilities. They have been traditionally applied to large customers, but smart grid automation can broad it's potential to more distributed users such as households and small buildings.
- The ancillary services program: It is based on the capability of load to follow the grid frequency signal. Current concepts already allow for aggregating distributed loads to implement frequency regulation actions by applying closed control strategies for reserve supply[99]. Future controllers would increase the demand capabilities for reserve supply and would operate it in a predictive mode, anticipating the reaction required in face of a frequency incident, and assigning a response to the more suitable supplier available (Palensky and Dietrich 2011). Therefore, part of the load will be technically enabled for frequency regulation actions. Since reserve supply is a continuous service which demands fast activation times, only the automated type of controlled load can be considered to be eligible for participating.

Even though, tariffs and incentives should be carefully designed to properly match the needs of the power system with the consumer's willingness-to-receive for enrolling in DR programs, thus, enabling the required level of flexibility for maximizing overall welfare. But, as price-signals are provided to customers in advance to influence their behavior, rates and bills should remain simple enough and understandable in order to be effective. To this end,

[99] For example, the Integral Resource Optimization Network (IRON) concept: https://nachhaltigwirtschaften.at/en/edz/projects/integral-resource-optimization-network-study.php

the principles exposed by professor Bonbright (1961) for an efficient rate design should be followed and probably extended[100].

Other issues dealing with the management of data gathered by the smart meters become also challenging in view of a massive expansion of smart meters at the customer level. The Council of European Energy Regulators (CEER) is aware of these challenges and has recently published guidelines dealing with the proper incentives for enabling demand-side flexibility (CEER 2016a, 2016c), the good practices for using this flexibility (CEER 2017b), recommendations for tariff design (CEER 2017a), and a review of current data management practices (CEER 2016b).

Those aspects open new institutional, regulatory and privacy issues, as well as new business opportunities; for instance, massive data management coming from smart meters would be an integrated task for network operation that is sensitive to competitive advantages to market players. Thus, data management responsibilities are associated with unbundling policies, which poses interesting governance questions about the model for data management and storing. These regulatory aspects will define new roles of unbundled DSOs as market facilitators, or invite third parties for data management tasks, either in a centralized[101] or decentralized[102] scheme.

[100] Indeed, the eight criteria for effective rate design outlined on the well-known book "Principles of Public Utility Rates" (p.291) by professor Bonbright (1961) would become even more relevant in the smart grid future. Prof. Bonbright's principles follow: 1. The "practical" attributes of tariffs. 2. The freedom from controversies as to proper interpretation. 3. The effectiveness in yielding total revenue requirements under the fair-return standard. 4. The revenue stability from year to year. 5. The stability of the rates themselves. 6. The fairness of the specific rates in the apportionment of total costs of service among the different customers. 7. The avoidance of "undue discrimination" in rate relationships. 8. The efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

[101] This is the case of the independent central data hub (CDH) which is a regulated monopoly that cannot be active on other areas of the electricity supply chain. The UK has followed this figure by creating the Data Communication Company (DCC)

[102] This figure is based on the principle of creating a competitive market for provider of data management services. Therefore, the Data-Access Point Managers (DAM) figure is created offering an interface between the customers, who store their own data locally, and the commercial parties, which are previously selected by the customers to exploit this data and commercialize their flexibility. This figure is being used in Belgium and Norway.

FROM A MONOLITHIC UNDERSTANDING OF DR TO CLASSIFIABLE CATEGORIES OF DR SERVICES

Due to their ambitious clean energy agenda, California is one of the pioneering states in the U.S. doing research on DSM capabilities. In a recent study[103] of the Lawrence Berkeley National Lab., a comprehensive evaluation of the potential of DR in California was conducted. The report uses extensive data analysis[104] was conducted using real smart meter load shapes. Then, by the means of clustering existing and probable DR programs enabled by smart meters, a taxonomy of new DR services was proposed converging into four well-defined categories, namely: shape, shift, shimmy and shed.

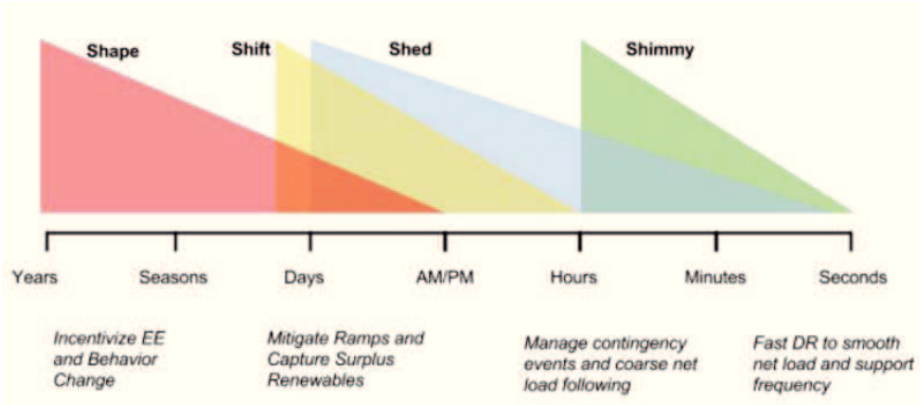


Figure 44. Categories of DR services. Source: (Alstone et al. 2017)

The bottom-up approach implemented in the study applies a data and computation intensive, but rather simple and robust methodology which is summarized in the following stages: The compilation of the hourly load-shape data at the user-level to build "clusters" of users defined by shape, total load and end-use (LBNL-Load method). These clusters are then divided into the DR categories commented (see Figure 44) to further use in the valuation of DR services. Then, the clusters are used to build DR pathways based on load forecasts for 2025, which results in annual supply curves of DR defined by the willingness-to-participate of users collected in the dataset and the quantities available by this year (DR-Path method). Finally, each DR category is evaluated on a power optimization model that includes endogenous capacity investments, which allows capturing the overall costs avoided at the

[103] See (Alstone et al., 2017) on the references.

[104] The data constitutes load shape measures from smart meters of 200000 sites (out of 15 million users), combining specific loads of the residential, commercial and industrial consumers, during the year 2014.

system level when considering the particular DR category (RESOLVE method)[105]. A cost-based parametric analysis is conducted for every DR category. This result pairs of system value and optimal DR quantities. The assembly of these pairs builds the levelized-value demand curve for every DR category. The levelized-value demand curve and the supply curves for every DR category can then be compared.

Following this methodology, relevant results on the value of the specific DR services are depicted for the Californian electricity market [106]. The study uses precise data for representing cost and availability of DR participation, accurately forecast the DR resource for the 2025 horizon and gives interesting insights on the system value of an enlarged range of DR services summarized in simple categories. Yet, the value of DR services is accounted on a one-by-one basis by the RESOLVE method, missing to estimate the eviction effects across overlapping DR categories due to competition (see Figure 44). In addition, the impact of grid storage investments over the value of DR is disregarded because only behind-the-meter (BTM) storage are considered by the DR categories, but no front-of-the-meter storage is included in the investment portfolio of the RESOLVE model.

Aside the interesting results obtained by Alstone et al. (2017) and the exclusive real data usage, the methodology implemented in their study was remarkably innovative for the valuation of DR capabilities. The strategy of characterizing the multiple DR services into four simple categories was not innocent. It is justified in the following terms:

> *"The choice to reframe market products into the more generic services framework was a conscious one, designed to ensure the results of the study are broadly applicable for future market structures that may not match current-day approaches".* (Alstone et al. 2017) *p. 3-15.*

Furthermore, they also comment on their intention for setting such shorthanded lexicon while naming their categories:

> *"The short names trade detail in their specificity for broader and more accessible concepts in grid management, and facilitate discussions between building scientists,*

[105] This procedure is similar to that exposed in the previous chapter applied for the valuation of electric energy storage.

[106] California Independent System Operator (CAISO).

policy analysts and power systems experts without necessarily requiring specific and esoteric knowledge of California market processes". (Alstone et al. 2017) *p. 3-16.*

The proposal of these categories is indeed very practical. They not only allow for the translation of these accessible concepts to electricity markets other than the CAISO, by slight adaptation the stage of linking the CAISO markets with the generic DR categories (see Table 21); but also, they institute good practices for a consistent representation of DR modules on power system modeling. Therefore, it is worth briefly describing such DR categories as introduced in (Alstone et al. 2017):

Shape*: It represents the type of load that can be statically modulated. This flexibility can be either prompt by voluntarist participation, as for an energy efficiency action, or be the result of a fuel substitution, or by inducing predictable patterns of demand such as the application of a TOU rate scheme.*

Shift*: is defined as the capability of DR for moving the load to desired times along the day. Thus, shifts are energy-neutral on a daily basis. It is only a rescheduling of consumption determined by the needs of the grid for balancing the energy-only market (EOM). The result is a smoother net load modulated as to minimize issues related to peak load and deep valley periods, VRE curtailment and sudden ramping episodes. The main sources supplying load shifting services are thermal load uses, re-scheduling industrial processes, and BTM electricity storage (i.e., stationary batteries and EVs).*

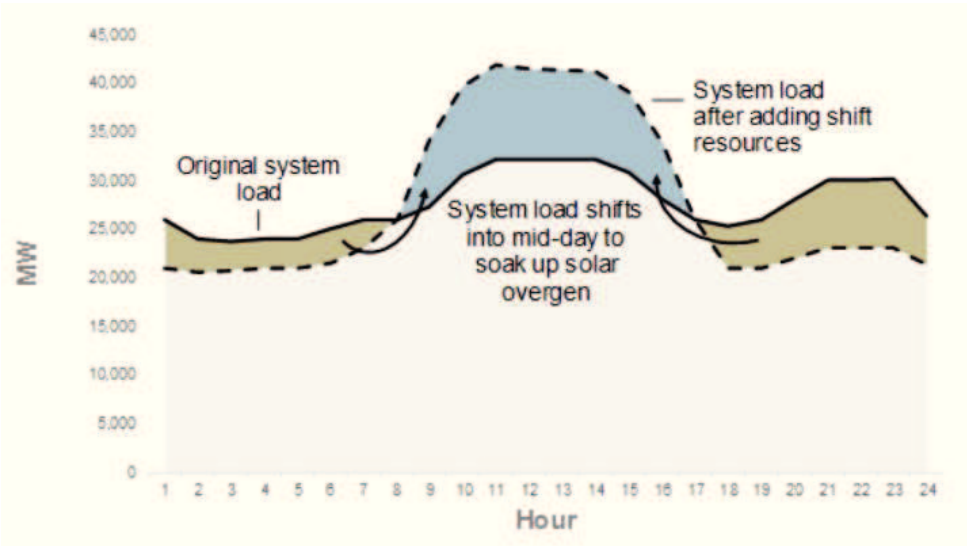


Figure 45. Example of load shift. Source: (Alstone et al. 2017)

***Shed**: it represents the part of the load that can be curtailed occasionally and upon request, in order to avoid capacity investments. Therefore, this category can be seen as the substitute of extreme peak generation capacity.*

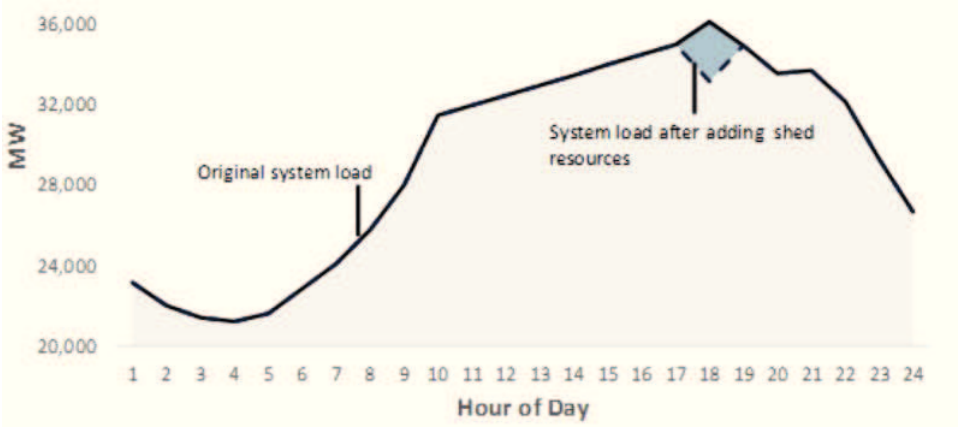


Figure 46. Example of load shed. Source: (Alstone et al. 2017)

***Shimmy**: it is constituted by DSM programs that can be automatically adjusted by the system operator. Its main value is in the supply of balancing services such as load following and frequency restoration. Therefore, it is referred as an ancillary service. It supports the grid by reducing the need for generation units to provide this service.*

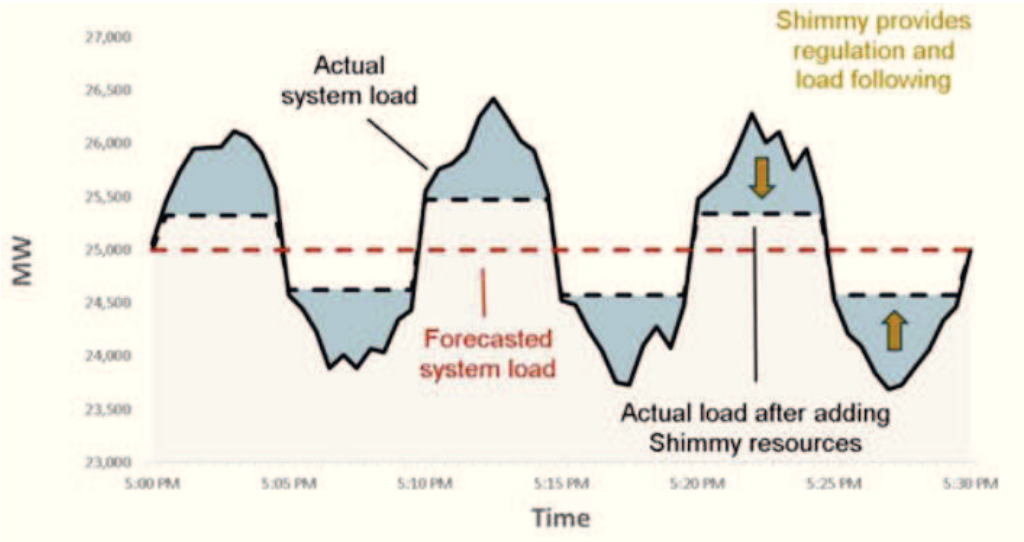


Figure 47. Example of load shimmy. Source: (Alstone et al. 2017)

The methodology and the findings presented in (Alstone et al. 2017) establish the foundations for appropriately representing the DR capabilities within the smart grid

environment, which, as it has been exposed above, has become a requisite for proper planning of future power systems.

	DR Service Product	California Market	Description / Notes
Shed	Peak Capacity	System and Local RA Credit	Resource Adequacy planning capacity. Requires participation as Economic DR resource and 4-hour continuous response capability requirement.
	Economic DR	Economic DR / Proxy Demand Resource	Resources in the energy market. (Proxy Demand Resource). RDRR can also bid economically in energy markets.
	Contingency Reserve Capacity	AS- spinning	Dispatched within 10 minutes in response to system contingency events. Spinning reserves must also be frequency responsive. CAISO currently has no established method for allowing DR to provide this.
	Contingency Reserve Capacity	AS- non-spin reserves	Able to respond within ten minutes and run for at least 30 minutes. The sum of Spinning and Non-spinning Reserves should equal the largest single system contingency.
	Emergency DR	Emergency DR / Reliability DR Resource	Resource can only be called when the system is in dire condition with limited dispatch. Not always in CAISO markets, however resources in these programs must register as Reliability Demand Response Resources (RDRR) in CAISO to access the wholesale energy market.
	DR for Distribution System	Distribution	Manage targeted issues. California is not currently deploying this type of DR but is the subject of study in the DRP. The capacity value is related to investment deferral in the distribution system.
Shift	Economic DR	Combination of Energy Market Participation	One mechanism for dispatchable shift could be participation in the energy market, both as a "load down" resource like PDR, and as a "consuming" resource in other hours. Current proposals in the CAISO ESDR could lead to bidirectional energy market structures like this.
	Flexible Ramping Capacity	Flexible RA -- energy market participation w/ ramping response availability	DR that counts towards flexible RA. Requires participation in the market with economic bids and 3-hour continuous response capability.
Shimmy	Load Following	Flexible Ramping Product (similar)	"Load Following" is modeled in RESOLVE as a symmetric flexibility product on a 5-minute dispatch. The CAISO Flexible Ramping Product is capacity that is awarded in the real-time market, for either increasing or decreasing load but without symmetric dispatch. The resources ramp in five minutes.
	Regulating Reserve Capacity	AS- Regulation	Capacity that follows (in both the positive and negative direction) a 4-second ISO power signal. It requires 1-hour of continuous response. Capacity is limited by the resource's 5-minute ramp.
Shape	Load modifying DR - Event-based	CPP	Utility-dispatched DR. This can be used to reduce an LSE's capacity for System RA requirement by impacting its forecasted peak load. This can be dispatched through power, reliability, or price signaling.
	Load Modifying DR - Load shaping	TOU	This is either Permanent Load Shifting or TOU style DR. This impacts the whole load shape, not just the peak. This resource is active every day and not dispatchable.

Table 21. Matrix mapping the CAISO markets to system service categories. Source: (Alstone et al. 2017)

3.3. METHODOLOGY

3.3.1. DIFLEXO: AN INTEGRATED ASSESSMENT FRAMEWORK FOR OPTIMIZING CAPACITY INVESTMENTS

The DIFLEXO model is a particularly adapted tool to conduct planning studies when considering significant shares of renewable energies, as well as policy and market issues. It is an optimization model that endogenously co-optimizes investments, operations, and reserve supply. Generation technologies, such as renewables and conventional, are considered side-by-side with new flexibility technologies, such as electric energy storage (EES) technologies and demand-side management (DSM), to supply the whole capacity, energy, flexibility and services required for balancing the system at least-cost.

DIFLEXO evaluates endogenous investments based on the merits and costs of every technology while considering technical interoperability on the supply-side to find a cost-efficient solution. It is particularly suitable to represent the impact of variability and uncertainty over the optimal capacity investments and to capture the effect of different energy policies over costs[107].

A comprehensive description of DIFLEXO is exposed in Chapter I, and further details of its implementation of the model are given in Chapter II. For the sake of parsimony, only a brief description of the model is exposed in this section, as well as the main model enhancements dealing with the representation of the advanced DSM capabilities that are expected to be enabled by the smart grid solutions are commented.

DIFLEXO is a partial equilibrium model that minimizes the total power system costs subject to technical constraints. It considers three interrelated markets within different time scales. Every market is represented as a block of service denoted by equality constraints. At the equilibrium, every block should be balanced. Technologies are classed by subsets, so, different subsets can participate in a determined manner for balancing every block. The blocks can be activated or deactivated as desired, as well as the contribution of every

[107] Energy policies such as portfolio standards, CO_2 caps, technology-oriented phase-out, capacity requirements, among others are easily represented as additional blocks of constraints by DIFLEXO.

technology to every block can be allowed or denied, assuring the complete modularity of the model. The model can be represented by the scheme presented in Figure 48.

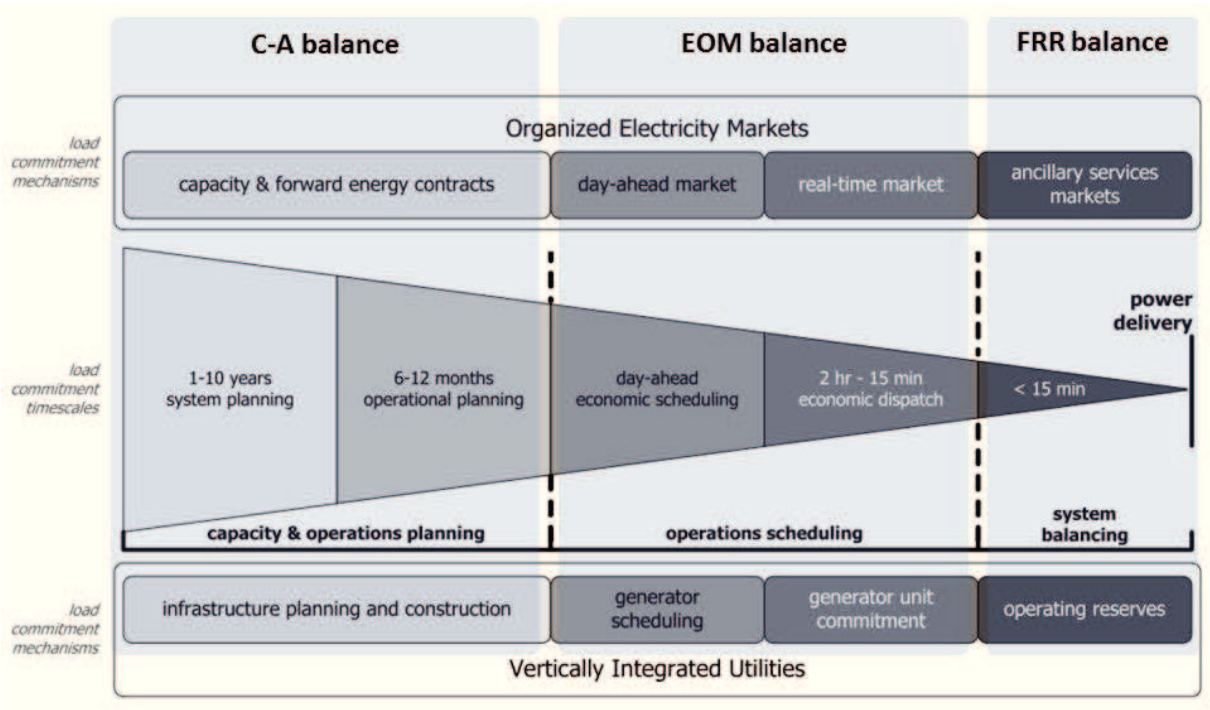


Figure 48. Schematic representation of power markets in DIFLEXO.
Source: Own elaboration from the scheme of (US Department of Energy 2006).

1. **Balancing blocks:** represent the balancing markets with different timescales. Namely, the balance of capacity-adequacy yearly-ahead (C-A), the operations and scheduling or the energy-only market (EOM) in the hour-ahead, and the reserve requirements[108] (FRR) minutes ahead. On the supply side, there are three groups of technologies participating to the balancing blocks, namely, the generation technologies, the storage (EES) technologies and the DSM capabilities. Each technology of every group is described by its technical constraints and related costs.
2. **Technical constraints:** these constraints articulate the system operations with the running cost of technologies to form multi-dimensional short-run marginal costs for every gate closure. Such constraints also describe the technical capabilities of every technology as a function of capacity investments, so, scarcity episodes can dimension the system endogenously.

[108] The reserve requirement is modeled as automatic and manual frequency restoration reserves, both in the upward and downward direction. Thus, four reserve markets.

3. **Energy policy constraints:** Can be tailored designated in the model. Energy policy such as capacity moratoriums, technology phase-out, carbon emissions constraints, and renewable energy portfolio, among others can be accounted.

New flexibility technologies, particularly the stock-dependent ones, such as the EES and the DSM, are comprehensively represented in the model. The integrated framework of co-optimizing investments, operation decissions, and reserve scheduling, while considering the technical capabilities and related costs of every technology, allows DIFLEXO to optimize the system based on the capabilities of every technology. The outcomes are the cost-efficient portfolio of capacities, the dispatch and the reserve schedule. Therefore, the model captures the value that every investment on capacity adds to the whole system, which is particularly relevant when assessing multiple technologies competing for the supply of multiple services.

It worth to be highlighted that, even if in some market configurations it is not still the case[109], following the examples exposed by Ahlstrom et al. (2013) dealing with the dispatchability of wind power, in DIFLEXO not only the VRE infeed can be curtailed to balance the EOM market, but also, wind capacity is able for supplying balancing services, namely, the supply of downward reserves, allowing some prized dispatchability to VREs in the long-term.

3.3.2. MODELING ENHANCED CAPABILITIES OF THE DEMAND-SIDE

In order to better represent the capabilities enabled by the smart grid technologies, the DIFLEXO model has been enhanced with additional DSM programs expected to be enabled in the smart grid environment. Those programs include some of the dynamic pricing and price-incentives commented in the previous section and are presented in Figure 43. At the same time, the convention proposed by Alstone et al. (2017), who synthesized the different DSM programs into four DR categories, namely, Shape, Shift, Shed, and Shimmy (see Figure 44), was adopted. This was found useful for efficiently representing such services within the balancing blocks of the model, and, at the same time, it facilitates the interpretation of results.

[109] From a technical point of view, it would be possible that wind capacity participate in the supply of some balancing services, nevertheless, either because of the lack of incentives given by the existing support schemes, or the absence of any regulatory obligation, wind infeed only contributed to the EOM balance.

On its previous version, the DIFLEXO model considered just one kind of DSM representing load shifting and shedding services only participating in the balance of the EOM (Villavicencio, 2017). In that stage, the DSM allows for load modulations within a moving window dispatched by the system operator but with no reserve supply capabilities. It suitably accounts for the demand-side flexibility that large commercial and industrial customers can currently supply as they are the most immediate sources of flexibility. Such simplified representation of the DSM is convenient and gives satisfactory results when analyzing short and mid-term horizons under the assumption that the deployment of smart grid capabilities would remain moderate. Though, this simplified representation of DSM becomes incomplete when focusing on later time horizons. In the long-term, thanks to the development of smart grid solutions, the dynamic capabilities of demand are expected to be fully enabled for smaller and distributed customers as well, and new user-level flexibility sources might be also available[110]. Therefore, as the demand-side will play a completely active role in system management on the long-term, when considering the 2050 horizon, including further modulation capabilities in of DSM in the model seems necessary.

To represent a larger set of DSM capabilities on DIFLEXO, the previous two DR categories (i.e., shift and shed) were enhanced by incorporating new DSM programs, and by including higher detail on the formers. The DSM programs incorporated comprise two price-based DR and four incentive-based DR. This enlarged representation of DSM accounts for different kinds of customers and different types of usages. The enlarged DSM programs are detailed as follows:

a. Time-of-use (TOU) rate program: a demand-response based on a TOU rate distinguishing peak periods (e.g., 9h – 21h) and off-peak periods (e.g., 0h-9h and 21h-24h)[111], sending daily peak and off-peak prices to consumers to allow them to adjust their daily consumption patterns. This is useful to represent price-sensitive customers with some demand flexibility under voluntary participation programs such as residential users. Therefore, users adjust their load shifting constant volumes of energy from peak to off-peak periods daily. It can be used to represent a whole variety of domestic loads

[110] Namely, EV and BTM stationary storage.

[111] The definition of the periods can be adjusted at convenience in a monthly or seasonally basis.

including the EV charging. Since this is a voluntary program representing a type of DR, it is considered as a static type of modulation and cannot contribute to reserve supply.

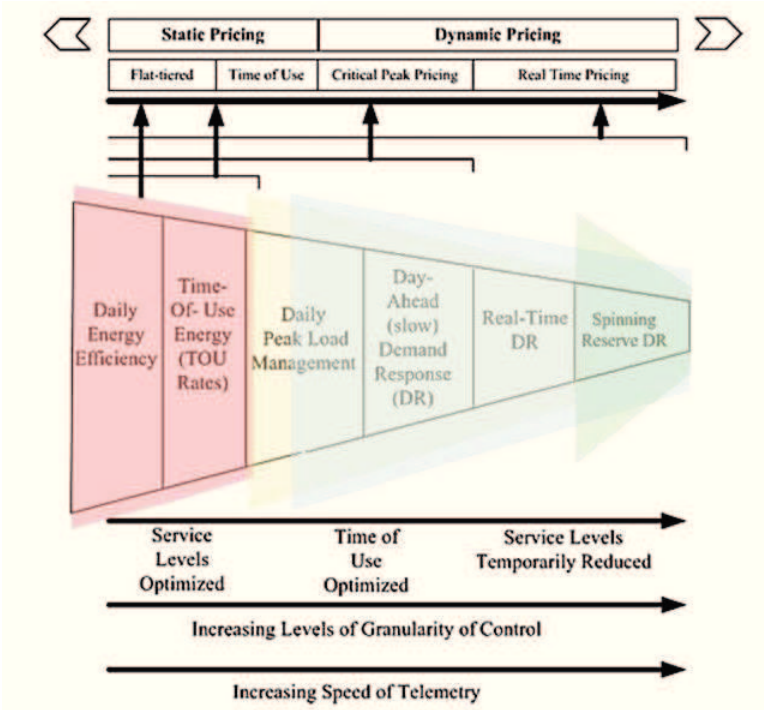


Figure 7. Schematic representation of different DSM programs.
Source: (Siano, 2014), modified as for integrating the DR categories.

b. Real-time (RT) rate program: an hourly-based real-time modulation, with voluntary participation, accounting for the part of load consumers can enable for continuous modulation. The operation of this flexibility can be programmed using smart energy management devices that automatically optimize the daily bill given the hourly price signals supplied by the utility, which at the same time are subject to minimum satisfaction constraints such as maximum shift duration, among others. This is expected to be easily done for usages such as smart white appliances and EVs, corresponding mainly to residential and some tertiary customers.

c. Dynamic management of sanitary usages: this option corresponds to a fully dynamic modulation of the load corresponding to an automated demand response (ADR)[112]. Load enrolled in such programs is directly connected to the utility's energy management system (EMS) who takes control of load modulations under customer's constraints. This category is convenient to represent highly thermal-inertia loads, which can be rescheduled without compromising comfort levels subject to utilization constraints such as maximum hours-per-day and minimum recovery times. Those loads correspond namely to space heating and cooling uses, and sanitary hot water consumption in the residential and tertiary sector.

d. Long-term industrial load management (LT_ind): It represents a DSM capability for automated load modulations on a window of 168 hours around the hour that load was expected to appear (i.e., a week ahead and a week after), with full load transfer. Therefore, every upward/downward shift is compensated by a shift in the opposite direction inside the time window. This allows representing low inertia production processes that can be rescheduled by the industry without harming the performance of production chains. Stepwise cost curves are used to represent different availability levels considering the user's willingness to receive for enrolling in such programs. A fixed operating cost is also accounted in order to cover the administrative cost due to process rescheduling.

e. Short-term industrial load management (ST_ind): It is similar DR than the previous long-term management option but that considers a smaller rescheduling window. For this category, only modulations of one hour around the expected hour are allowed. It similarly considers for a fixed cost accounting for the willingness to receive for enrolling in the program, but no operating costs are entailed due to the less restricted modulation regime. This kind of flexibility asset is suitable to represent industrial high inertia loads such as heating and cooling usages.

f. Load curtailment (LC) program: it accounts for the DR program for interrupting load for peak shedding during extreme episodes with an automated control. It can be deployed

[112] Further details on this evolutionary type of DSM can be found on the website of the Demand Response Research Center of the Lawrence Berkeley National Laboratory: https://drrc.lbl.gov/openadr

either by sending a price-signal higher than the willingness to pay of consumers enrolled in the real-time pricing program or by an order to shed load to enrolled interruptible/curtailable load participants. No fixed cost is accounted for using this alternative, but a high activation cost is incurred. It is considered as a dynamic source of demand-side flexibility because it can be managed by the system operator.

These DSM programs supply different services to the grid, so, they are linked to the former categories of DR services as presented in Table 22. Therefore, the upward and downward modulations, coming from of each of the DSM program, are accounted on each balancing block. The net modulation for every timescale is obtained by aggregating the individual contributions of every DR category. It is to be noted that the flexibility resource coming from behind-the-meter stationary storage, as well as EV, are included on the different DSM programs. The formal presentation of the model with the equations representing the new DR services is presented in the appendix.

Service type	DSM program	Balancing block concerned	Unit
Shape	• TOU rate program	On-peak/off-peak arbitrage on the EOM on a daily basis	MWh
Shed	• LC program	Hourly load shedding for balancing the EOM with financial compensation upon activation	MWh
Shift	• RT rate program • Short-term and Long-term industrial load management • Dynamic management of sanitary usages	Hourly arbitrage on the EOM specified by the length of the modulation given by the type of DR program	MWh
Shimmy	• LC program • Dynamic management of sanitary usages • Short-term and Long-term industrial load management	All the suppliers participate on the supply of upward FRR. All the suppliers participate on the downward FRR balance but load curtailment.	MW

Table 22. Mapping the DSM programs with DR categories.

3.4. A QUANTITATIVE ASSESSMENT OF THE FRENCH POWER SYSTEM BY 2050

3.4.1. HYPOTHESIS ON THE 2050 HORIZON

THE DEMAND-SIDE BY 2050

The scenario and of the French power system by 2050 was calibrated using the main hypothesis of the last study of the French Environmental and Energy Management Agency (ADEME 2015) on the topic for the same time horizon[113]. Thus, the power demand is consistent with that of the scenario "moindre maitrise de la consommation", which is an extrapolation of the "Nouveau mix" scenario estimated by French TSO (RTE) for 2030. Therefore, the annual demand was set to 510TWh, which represents an increase of 4% from the 2015's level. The hourly load for 2050 was calculated by applying this growth factor to the hourly demand of 2015. This homothetic transformation of the hourly load may be a strong assumption given that by 2050, meteorological factors, changes in consumer's behavior and new electricity usages, can radically change the shape of the electricity load. Nevertheless, it is a simple and still valid proxy that is regularly used by analysts in the absence of large bottom-up approach for aggregating demand. Nonetheless, the methodology implemented remains valid if more detailed data characterizing demand is provided.

Similarly, the estimates of the electricity use providing flexibility are based on the same report of ADEME (2015), but were updated by using the per unit values published by RTE (2017a). For instance, the following assumptions dealing with electricity uses were considered:

Transport sector: 10.7 million of vehicles, out of a total of 22 million vehicles, were assumed to be electric (EV) or hybrid by 2050. The charge of this fleet can be managed according to the DSM program assumed. This represents a total DSM potential of 15.6 TWh/year with a peak of 6.8GW for the ADEME, which results in a utilization rate of 26%. In order to obtain a convenient assumption for the part of the load that can be shifted, an average demand of 2 MWh/year per EV was assumed following the estimates of RTE (2017a). Given the total

[113] Further information can be found in the interactive website created around the findings of this study: http://mixenr.ademe.fr/

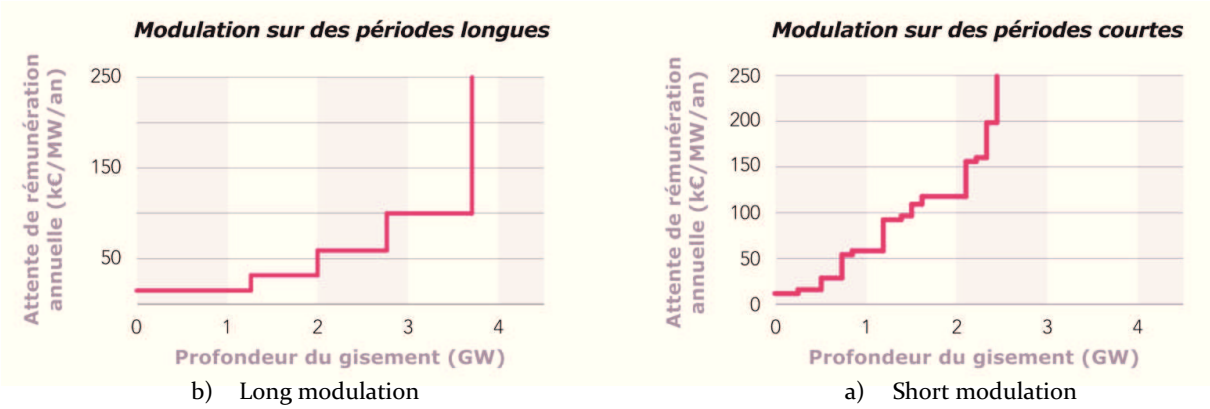
fleet of EVs, their unitary consumption, and their utilization rate, the total DSM capacity for this usage was estimated at 9.4GW, where 53% was assumed to charge under TOU rates (i.e., mainly residential charging stations), thus serving for Shape DR, and the remaining under static control (i.e., mainly commercial charging stations), serving as shift DR.

Sanitary hot water: According to the same report, the entire residential hot water appliances will be managed across the day, representing a DSM capacity of 6.7 TWh/year with a peak of 2.6 GW. Thus, a utilization rate of 27% is obtained. Assuming the values reported by RTE (2017a) for this usage, each household consumes 1.55 MWh/year. Assuming their hypothesis based on 7.6 million households using electricity for this service, this usage represents 5 GW of flexibility. It was also assumed that 93% of this capacity is controlled statically, while the remainder can be managed dynamically by advanced control strategies, therefore, capable of supplying balancing services on the grid.

Electric heating and cooling: Accordingly, electric heaters of 75% of the residential sector (21.9 million households), and 15.6 million of commercial buildings will be dynamically managed; representing 34.8 TWh and 25.4 GW for DR shifts. Only appliances of the residential sector were considered.

White appliances: They represent around 50% of residential consumers. The report estimates that 75% of the households will allow for managing this load, thus, 7.7 TWh/year and 2.85 GW peak. Assuming a utilization rate of 16% this comes to 0.48 GW on an hourly basis.

Industrial uses: This source of DR can be used for long and short modulations. Figure 49 presents the cost curves assumed. They represent the willingness-to-receive of the industrial and the tertiary sectors to supply grid services of the form of DR. Those curves are the results of a project estimating the DSM capabilities with real data of the French industry which will be published by ADEME by September 2017.



b) Long modulation a) Short modulation

Figure 49. Industrial DR supply curves. Source: (RTE 2017b)

THE SUPPLY-SIDE BY 2050

Generation and storage technologies considered by 2050 are based on the technological prospects presented in Section I. Cost of technologies are based on the JRC (2014) estimations for technology evolution towards 2050.

The supply-side can be classed by technology and fuel as it is the convention. Renewable technologies are mainly constituted by hydro reservoir power plants, wind and photovoltaic (PV) technologies, which are modeled endogenously in DIFLEXO. Biogas, biomass, and electricity from waste were also considered but with exogenous shares given their marginal potential for further development. Provided the current developments on wind forecast, as discussed in section 3.2, wind has been assumed totally dispatchable through wind curtailment. Likewise, it was assumed that wind will be responsible for balancing the energy-only (EOM) and the downward FRR markets. The infeed of PV can also be curtailed, but it only contributes for balancing the EOM.

The set of electric energy storage (EES) technologies considered consist on pumped-hydro storage (PHS), Li-ion batteries (Li-ion), hydrogen with fuel cells (H2-FC), and three types of compressed-air energy storage (CAES), such as underground CAES (undCAES), aboveground CAES (aboCAES) and adiabatic CAES (AA-CAES). Such technologies can supply very similar kind of services, but differ on the extent of the stocks, so the duration that they can provide arbitration and system services. As it was presented in Chapter I and II, investments in EES are optimized considering the capacity and energy dimensions separately for every technology. Those technologies correspond to in-front-of-the-meter storage, which cost figures correspond to bulk units.

The main hypotheses adopted on cost and technical performance of generation and storage technologies are summarized in the appendix.

3.4.2. BETWEEN ENERGY PLANNING AND ENERGY POLICIES: IS THERE A PLACE FOR THE MARKET?

By 2050, the official target released under the French National Low-Carbon Strategy (NLCS) in November 2015 is to achieve a 96% CO2 offset referred to the levels of 1990[114]. At the same time, the French administration advocates for a profound energy transition towards renewables.

Therefore, these orientations open relevant questions in term of the possibility of a market-driven transformation of the French power system, or the need for a regulatory intervention through energy policies. But also, the uncertainties on the existence of a due regulatory framework allowing the cost-optimal development of storage technologies, as well as those related to the deployment of smart grid capabilities. It seems necessary to accurately assess the role of such new flexibility technologies on fostering the decarbonization and energy transition objectives.

In order to analyze the interactions of the different regulatory and policy components with evolving technologies, the following methodology is proposed:

1. Adopting a skeptical posture on the development of flexibility: this can be done by simultaneously considering factual and counterfactual cases. The factual case assumes that cost-optimal investments on flexibility are possible; the counterfactual case impedes any investment in new flexible technology. So, in a situation where no flexibility is cost-optimal, both cases would converge to the same equilibrium.
2. Assessing the "market-driven" equilibrium: the CO2 emissions and the RE shares resulting from a "laissez-faire" energy policy needs to be evaluated before arguing for the implementation of any policy. Thus, the main need for a regulatory

[114] The official communicate stresses that the sectorial targets affecting the power system are still indicative, but gives a clear vision of the very ambitious objectives pretended towards 2050. Further details can be found at:

https://unfccc.int/files/mfc2013/application/pdf/fr_snbc_strategy.pdf

intervention might be discussed. Any gap on the outcomes should be properly discussed before concluding in favor for a regulatory intervention[115].

3. Least-distortive policies: in the case where an intervention may be justified, it should be introduced in a progressive and least-distortive manner through sound energy policies. To that end, two set of policies are considered, namely, a carbon policy constraining over the specific emissions of the system (i.e., in gCO_2/KWh), and the enforcement of a renewable portfolio standard (RPS) targeting renewable energy shares.

In such a framework, energy policies can be assessed in an accurate and fair level. In the current context of liberalized electricity markets, proper planning means appropriately choosing and calibrating the best set of policies capable of giving the right incentives for achieving sound objectives.

For instance, the assessment of a carbon policy and an RPS in the previously exposed terms is not an innocent choice. They are the conditions for an agnostic assessment of any regulatory intervention. The rationale behind the assessment of a regulatory intervention by considering such high-level policy instruments is to preserve the focus on the shock they involve, rather than discussing on their implementation. A carbon policy can be implemented through a carbon tax on emissions, or a market-based mechanism such as a cap-and-trade scheme, or by enhancing existing CO_2 schemes like the EU ETS[116] by introducing national price floors. Similarly, the enforcement of an RPS can take the form of a mandate, a support scheme for improving RE project finance, a tendering system based on RE capacity installed with long-term contracts, the adoption of tradable clean energy credits, feed-in tariffs, feed-in premiums, among others. But the objective of this chapter is to assess the need for such policies rather than discussing on their implementation.

[115] It should not be overlooked that any regulatory intervention is not a risk-free strategy. Policies may also fail on improving the pretended outcomes due to inadequate design and/or poor implementation.

[116] European Union Emission Trading System: https://ec.europa.eu/clima/policies/ets_en

3.4.3. PROPER PLANNING THROUGH PROPER POLICIES: A QUANTITATIVE ASSESSMENT FROM ENERGY ECONOMICS

MARKET FAILS ON CORRECTING ENVIRONMENTAL EXTERNALITIES: ON THE NEED FOR A CARBON POLICY

This section investigates the carbon emission levels resulting from a "laissez faire" policy by 2050 and discusses on the extent of a market-driven clean energy transition. Thus, the need for introducing a regulatory intervention of the form of a carbon policy would be investigated.

The historic CO2 emission levels, as well as the future goals released by the French administrations are presented by the dashed lines of Figure 50. The points of the figure show the carbon emission outcomes related to the VRE shares obtained with the only introduction of a carbon policy. The solid line connects the points under the assumption that cost-optimal flexibility can be deployed, while the dashed line represents those where neither DSM, nor EES are deployed in the system, so defining the counterfactual cases. In that way, the solid line corresponds to the ideal situation with no barriers on the cost-optimal development of flexibility. These results can be challenged against the counterfactual case to obtain a range of possible states contained in between. This range describes the suboptimal development of flexibility that may result from regulatory veils and/or market imperfection[117].

The business-as-usual ("BAU") points of Figure 50 correspond to the global equilibrium states in the absence of any carbon policy provided the official cost prospects. These points represent the states over which the marginal benefit of every market participant is zero under the assumption that there is no regulatory intervention constraining the equilibrium, thus, representing a pure "Laissez-faire" energy policy. For the sake of self-consistency, they would be used as the reference points, or standard states, for calculating the evolution of the equilibrium resulting from any regulatory intervention[118]. Hence, any move from the

[117] This question was addressed in chapter II. The optimal-development of storage faces important challenges coming from market imperfections, regulatory barriers, to information asymmetries.

[118] A regulatory intervention is here presented by the set of distortionary policies that would affect the marginal profit of technologies, such as carbon tax, pollution allowances, green certificates, among others, but also any kind of technology-oriented policy like the introduction of a target on the shares or capacity over any specific technology, such as nuclear phase-out policies, coal moratoriums and a RPS.

reference cases (i.e., "BAU" points), either by increasing the VRE shares above these levels, or by offsetting the CO_2 emissions below these levels, would imply a more constrained equilibrium, so, necessarily incurring in supplementary costs. It is worth noting that the "BAU" points result from the hypothesis adopted. Different cost prospects, drastic shocks on the fuel prices, or even, different profiles of VRE generation and demand, would change the coordinates of such points.

The remaining points denote the constrained equilibrium states related to the only introduction of a carbon policy, thus, present the resulting CO_2 offsets and the optimal shares of VRE as a function of carbon policies. Similarly, these points represent the cost-optimal investments in VRE capacity that would enter the market without any subsidy for every level of carbon policy. The resulting energy shares related to these points are presented in Figure 51.

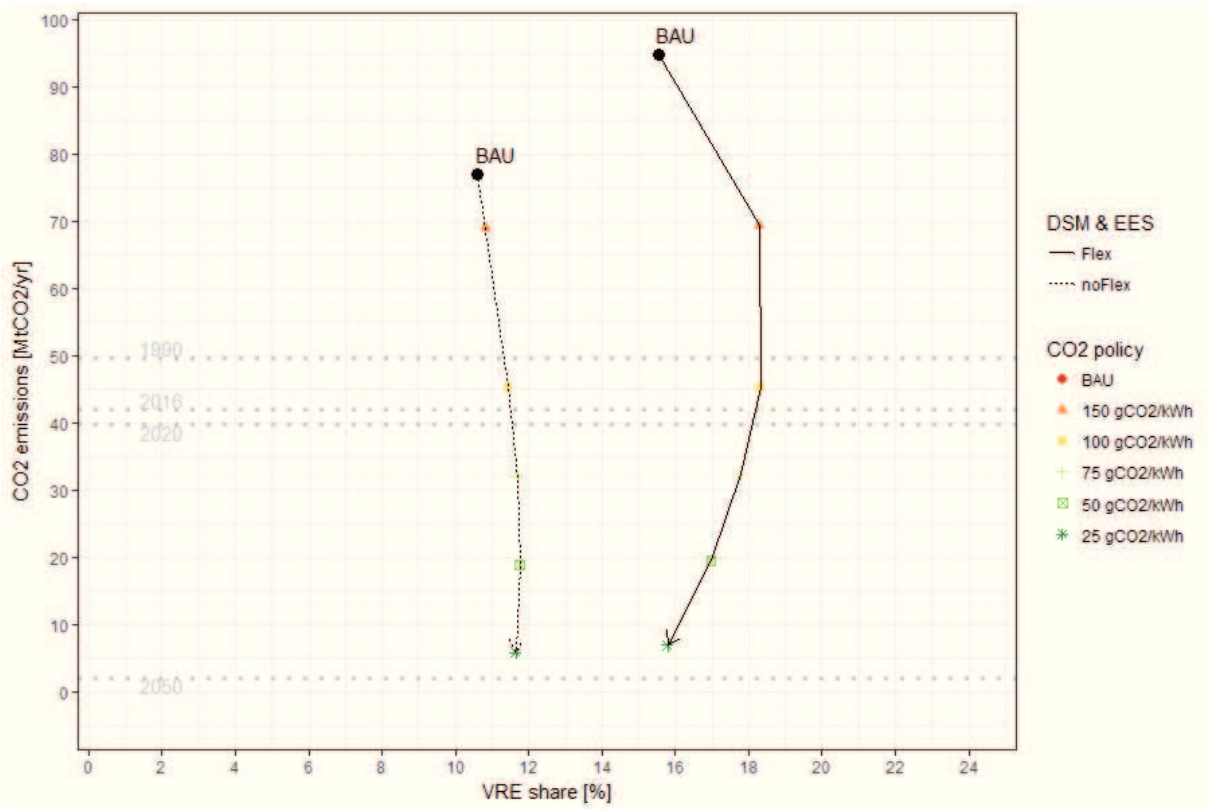


Figure 50. The optimal shares of unsubsidized VRE by 2050

As it can be seen from Figure 50, the application of any CO_2 policy would unambiguously stem the system to new equilibrium states with lower CO_2 emission levels regardless the VRE penetration, and notwithstanding the presence of flexibility in the system. Thus, as

expected, the direct effect of introducing a carbon policy is verified by the drop in the total level of emissions. But the CO2 offsets are only slightly related to an increase of the VRE shares.

Around 16% of market competitive VRE shares appear to be cost-optimal by 2050 without any kind of support and including balancing responsibilities through infeed curtailment (see BAU points of Figure 50). This represents a significant increase on the optimal, non-subsidized, shares of renewables when compared with current levels[119]. This increase is in part explained due to the promising cost reductions of VRE technologies, but also due to the enhanced flexibilities deployed by the smart grid capabilities enhancing the integration of variability. In the counterfactual case, only 11% of VRE shares are cost effective.

While it is correct that stringing CO2 policies enable higher VRE shares to break-even, this effect results very meager. As it can be seem from Figure 50, it is flexibility which boosts the cost-optimal development of VRE. Its penetration rises by 4 to 7% depending on the carbon policy level when optimal flexibility is allowed. Restrictive CO2 policies mainly cause the decline of coal shares, and the increase of nuclear. In the absence of a RPS, loosely to moderate CO2 policies slightly enhances the cost-optimal deployment of VRE with a 2%-4% increase of unsubsidized VRE (see Figure 50), while moderate to strict policies progressively increases nuclear shares, and take back the VRE shares to levels close to the "BAU" points. This digressive effect is intensified in the case with optimal flexibility. This effect is explained by the fact that, under the cost assumptions adopted and given the low availability of VRE, nuclear power dominates VRE technologies in term of system-wide marginal abatement cost[120].

Thus, it can be introduced that any cost-efficient decarbonization strategy would necessarily encompass an increase in the shares of nuclear rather than those of renewables. This finding

[119] The VRE installed capacity is currently developed under support mechanisms and subsidies enhancing project's break-even.

[120] On this point, the definition of system-wide abatement cost is central. It is the system cost of reducing a unit of CO2 emissions from the system relative to technologic specificities, so, considering the specific carbon emissions by technology with their capital costs and operating costs, but also, the integration costs and profile costs in the case of VRE. In a simple LCOE framework, VRE may have lower costs than nuclear, but this metric ignores any change on the capacity factors of technologies coming from different dispatches at different VRE penetration levels. More importantly, the LCOE ignores the exacerbated needs of system services required by increasing shares of VREs. A better correlation between VRE infeed and load, disruptive extremely low-cost storage, or different relative fixed and variable costs of technologies would change the abatement costs between technologies.

may challenge the widely held opinion stating that the application of constraining CO2 policies (e.g., a high CO2 tax) would directly be traduced by a wide deployment of VRE technologies without the need for any other subsidy. Although the promising cost decrease assumed for renewables and storage, and even with the extended deployment of smart grid capabilities expected by 2050, an extended and market-driven clean energy transition by 2050 would be out of the scope.

As it is presented in Figure 50, the optimal shares of VRE stay in the range of 11% - 19% by 2050, depending on the CO2 policy level applied and the degree of deployment of flexibility (i.e., dynamic tariffs, smart grid and storage). The power system deployed under the "BAU" case is not completely different than today's. While by 2050 wind capacity increases to around 30 GW, meeting that of nuclear, the system is still largely dominated by conventional technologies, hence, keeping a centralized structure on the supply-side. On the demand-side, there is more revolution with the management of higher DR services[121] (see Figure 51).

However, the "BAU" points expose a twofold increase of CO2 emissions compared to 1990. So, it is worth giving some perspective on this result: The specific CO2 emissions of the French Power system has been among the lowest in Europe during the last 30 years. Figure 52 presents the trend of the specific carbon emission of some European countries. The very low levels of the French power system are explained by the technology-oriented policies impelling a turn to nuclear power after the severe oil shocks of the 70's[122]. During the next decades, the technological push was substantial. By the early 80's, the French power system started to be largely dominated by nuclear power. However, there were no a liberalized of the electricity markets by that time, this was a period of a public utility on the supply-side operating as a regulated monopoly. Energy policies were dictated by a central planner whose main concerns were those of security of supply. The push towards nuclear was defended by arguing fossil-fuel independency and was supported by the economic spill-overs that would have place through the development of a brand new industry. Thus, by 1990, the specific emission level of the French power system was already seven times lower than the German

[121] The main evolution towards a decentralized system configuration is determined by the 9GW of Shape DSM and the 7 GW of Shift DSM that should be managed. But, this represents only a revolution of the demand-side rather than a drastic business model change for current utilities (see Figure 51).

[122]A detailed view on the history of nuclear power in France is developed in the awarded book "The Radiance of France: Nuclear Power and National Identity after World War II" by Gabrielle Hetch, which has also been commented by Picon (2001). https://mitpress.mit.edu/books/radiance-france

and five times lower than the European average. The current exceptionally low emissions are the unintended but inevitable product of such a coordinated regulatory shock that involved the energy and the industrial sectors.

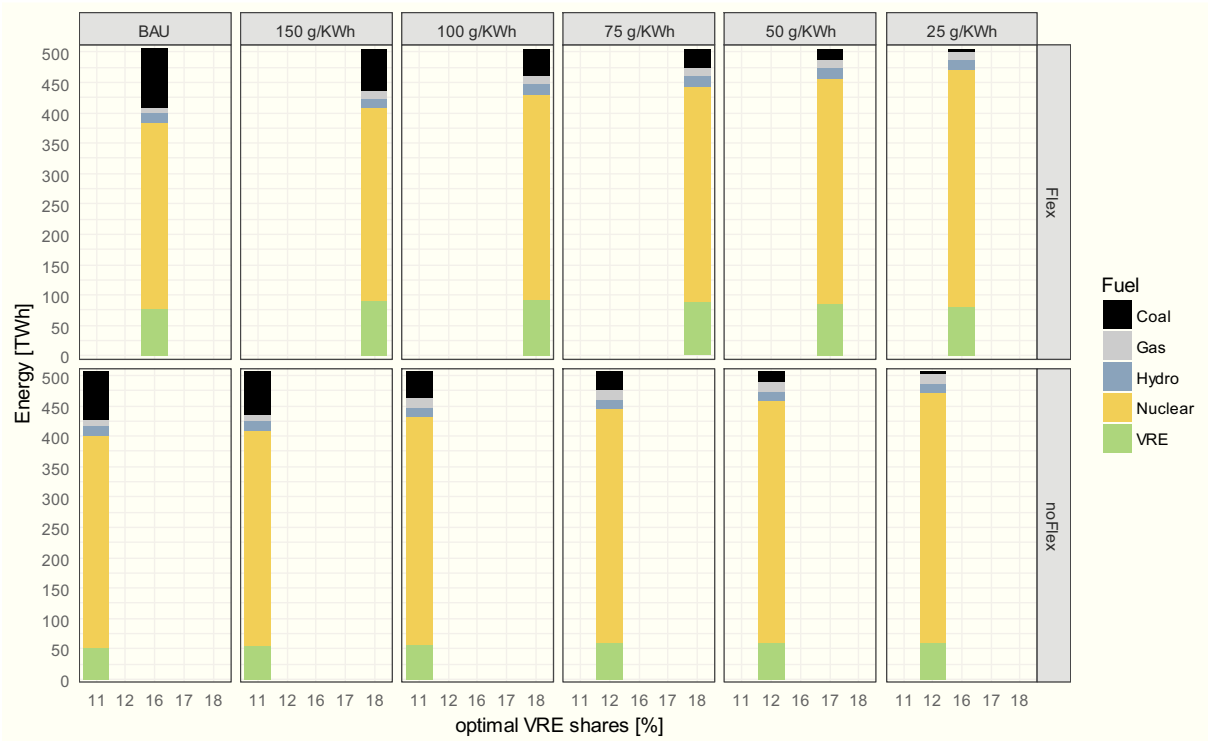


Figure 51. Energy mix by fuel under carbon policy constraints

By comparing the enormous gap separating the emissions levels of France with the European average it can be depicted the extent until which the French power mix has been intervened[123]. This also evidences the very dissimilar effort required for replacing and rebuilding the existing power system while satisfying any decarbonization objective referred to the emissions levels of 1990. By doing so, policymakers may engage on very challenging goals, which are referred to a quite no standard state of the system that was obtained during times of straightforward regulatory intervention.

[123] A view on this issue is developed by Perrier (2017). Figure 61 in the appendix also presents the drastic uptake of nuclear power since the early 80's.

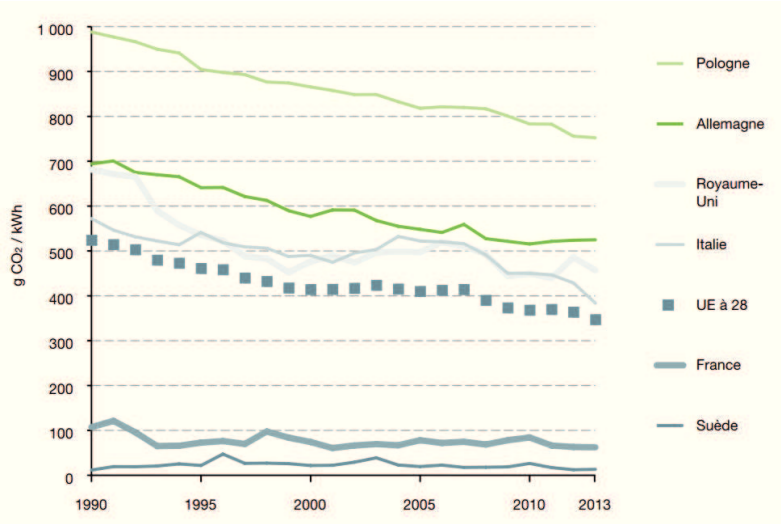


Figure 52. Specific emissions of some European power systems. Source: IEA 2015

Thus, even if the emission levels obtained at the "BAU" points, compared those of 90's, may not appear very promising, they should not be considered as completely unsatisfactory. They are the product of a "laissez-faire" policy, so, without any kind of intervention, contrarily to the somehow doped levels seems during the last three decades and including those of 1990.

In that sense, if the French power system may be totally rebuilt by 2050 in the current context of liberalized electricity markets, which means a market-driven Greenfield development of the power system, similar CO_2 emissions levels could be obtained by applying a carbon policy of around 75 gCO_2/KWh. In such case, as it is presented in Figure 51, the system would converge to an energy mix composed by between 80-79% of nuclear shares, 13-17% RE shares and the 7-5% of fossil fuel technologies depending on the deployment of flexible capacity, and where the RE shares obtained are mainly composed by wind and hydropower. The extent of the RE penetration and its composition is dependent on the amount of flexibility developed in the system. Assuming an optimal deployment of DSM and EES technologies, the system would be capable of integrating 4% more wind without subsidies on this policy scenario, but a complete energy transition seems largely out of the scope by implementing a carbon policy alone.

MATERIALIZING THE FRENCH ENERGY TRANSITION: ON THE INTERPLAYS BETWEEN ENERGY POLICIES, ENVIRONMENTAL POLICIES AND FLEXIBILITY TECHNOLOGIES

The previous section exposed the impossibility of a carbon policy alone to trigger a broad market-driven energy transition. These section extends the set of regulatory interventions by introducing the effects of a renewable energy portfolio (RPS) for targeting significant shares of renewable energies.

For the sake of parsimony, the analysis proceeds by targeting specific RE levels higher than those obtained by the "laissez-faire" policies. Therefore, the effect of such regulatory interventions is a new equilibrium state located to the right of the "BAU" points previously introduced in Figure 50. These points correspond to the implementation of an RPS imposing of 50 and 80% of RE shares in the energy mix. Therefore, Figure 53 and Figure 55 should be seen as an extension of the segments presented in Figure 50, where the case with and without new flexibility were analyzed respectively. Furthermore, even if dispatchable RE sources (i.e., biomass and biogas) and reservoir hydro technologies are accounted for satisfying the enforced RPS, the horizontal axis of both figures is presented as a function of the VRE shares obtained in every case. This change of variable allows isolating the effect of VRE for a better understanding of the impact of variability. So, the 50 and 80% of RE targets correspond to that the points of 46 and 76% VRE shares respectively. This shift is given by the shares of dispatchable RE resources satisfying the RPS constraint. As previously commented, dispatchable RE sources were assumed to be caped on capacity due to maximum availability levels.

In that framework, the case in which optimal flexibility can be deployed is compared with the counterfactual case while looking at the impact of regulatory intervention over the total CO_2 emissions and the VRE shares. Results can be subdivided as follows:

a. Targeting higher VRE shares in the absence of flexibility technologies

This case is presented in Figure 53 for a detailed scrutiny. It can be seen that CO_2 emission rapidly decreases with VRE for low to mid VRE penetration levels. At these levels mainly hydro and wind capacity are developed, while very few solar is deployed. The system can accommodate the variability of net load variability without difficulties due to available capacity of hydro and the fast response gas-fueled units. This results in a very favorable

ground for wind integration, which leads to a first fuel switching. There is a progressive fuel switch from coal to renewables due to the enforced RPS, driving down CO2 emission levels (see Figure 54). But this trend follows a concave behavior. The CO2 reductions reach a plateau between 50 and 60% of VRE shares depending on the carbon policy. The plateau appears due to the fact that increasing VRE shares made CO2 restrictions to become progressively unbinding, so, loosening the policy and letting the fossil-fueled capacity still in place freely pollute. In a market-based CO2 scheme, such as a cap-and-trade system, this effect would be illustrated by a drop in the price of the emission permits due to an excess of supply.

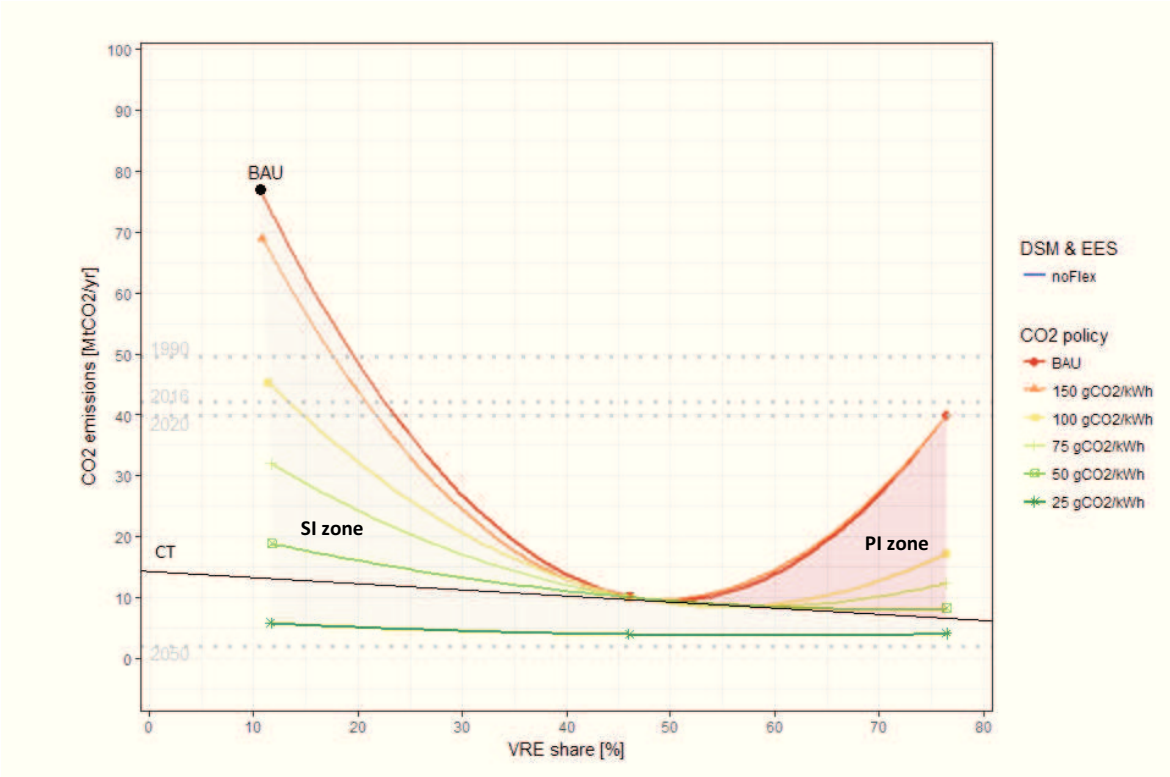


Figure 53. First and second fuel switching without flexibility

At these VRE shares, hydro power attains its maximal cap[124], and only wind and PV can be further deployed to achieve higher RE penetration. During this phase, the integration of variability experiences a different path. Higher VRE shares request even higher flexibility levels, that in the counterfactual case (i.e., in the absence of new flexibility technologies), it can only be supplied by fast gas-fueled technologies, which are more adapted for

[124]The capacity of reservoir hydro was constrained by the availability of the resource at around 9.2 GW for France.

accommodating variability, and can break-even with lower capacity factors than nuclear. Therefore, a second fuel switching takes place. It consists in a switch from nuclear to RE and gas (see the energy shares of Figure 54). During this phase, even if the contribution of carbon-free RE shares increases, the net effect of the fuel switching is a progressive CO2 rebound. This effect is exacerbated when VRE penetration is enforced with untightened CO2 policies, causing coal generation to also regain some of the shares from nuclear, for mid-load supply (see Figure 54).

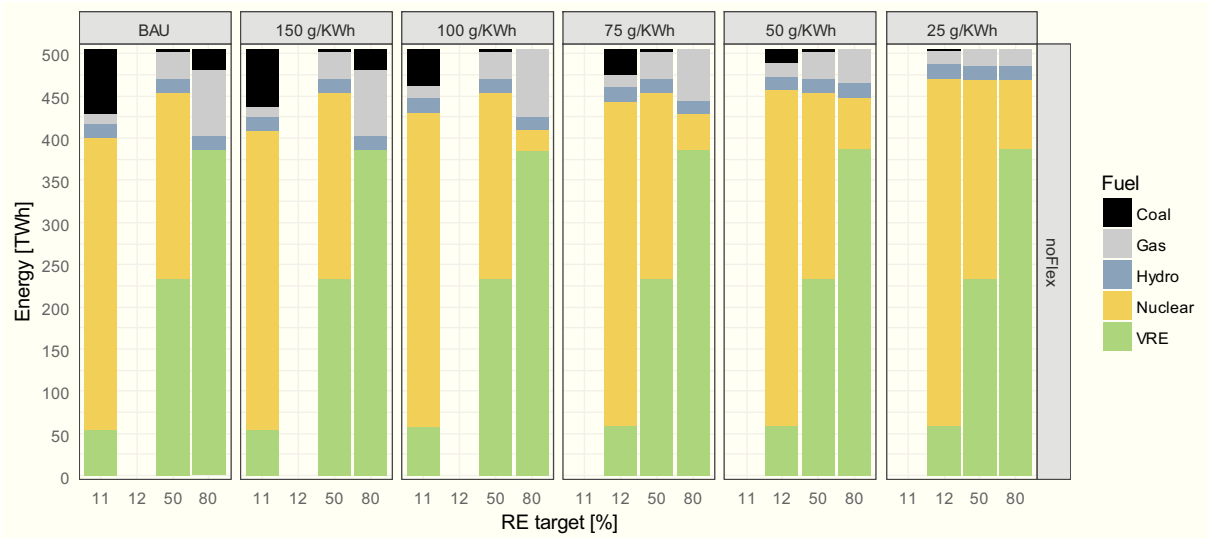


Figure 54. Evolution of energy shares with no investments in new flexible technologies

For example, with a carbon policy of 50g CO2/KWh or above, the emission levels obtained under a target of 80% VRE penetration are almost as high as that obtained in the absence of any RPS due to the rebound effect. In terms of an optimal CO2 offset, the optimal strategy would be to limit the target of the RPS to the levels corresponding to the vertex.

Moreover, the vertexes of less stringent carbon policy curves share a common tangent (i.e., the line CT in Figure 53). As exposed by Delarue and Van den Bergh (2016), at certain levels of RE penetration, unrestrictive carbon policies may become superfluous. A marginal increase on the carbon restriction would send increasing price signals to the market, causing an increase in the marginal profitability of low-carbon technologies for energy supply but also for the supply of flexibility[125], reducing the shares of carbon intensive technologies, so,

[125] In the counterfactual case, the low-carbon flexibility comes from gas technologies but also from increasing the use of nuclear capacity for load following purposes when possible, and by increasing the balancing contribution of VRE with infeed curtailment

progressively inhibiting the second fuel switch, and shifting the vertex slightly towards higher VRE shares. Thus, the line of common tangent relates all the unbinding carbon policies. These policies are in delay with respect to the enforced RPS.

The line of common tangent gives further relevant information. It defines the frontier between two policy zones as showed in Figure 53 : a zone of scrupulous intervention (SI zone), shaded in grey, where policies contribute to carbon offsets while increasing VRE shares; and a zone of pernicious intervention (PI zone), shaded in red, constituted by the delayed policies previously evocated. Only sufficiently constraining CO_2 policies can further induce CO_2 offsets with increasing shares of VRE. Based on the hypothesis adopted on this case study, this frontier is placed at around 40gCO_2/KWh.

b. Targeting higher VRE shares with the optimal development of flexibility technologies

This case is presented in Figure 55. By looking at the starting points of the figure it can be seen that the amounts of cost-optimal shares of VRE are higher than that obtained without flexibility at similar CO_2 policies. Flexibility allows around 5 to 7% more VRE integration but does little for CO_2 offsetting at constant CO_2 policies (see Figure 55).

As it can be noted, all the curves are upward shifted with respect to the counterfactual case, and the shift is inversely proportional to the CO_2 policy level. This is, the no policy curve is largely shifted while the policy of 25gCO/KWh is not shifted at all. The curves corresponding to policies in between are progressively more shifted as the restriction is less constraining. This effect is given by the fact that flexibility would trigger time arbitration based on electricity prices, thus, increasing the capacity factors of low short-term marginal cost (STMC) technologies, such as base and mid-load units, and decreasing that of high STMC technologies, such as peak and extreme peak units. Therefore, non-constraining carbon policies don't send high enough price signals to put carbon-fueled technologies out of the merit, when integrating flexibility is allowed, it produces an increase in the shares of renewables, but there is also an increase on the shares of nuclear and coal with respect to the counterfactual case, where flexibility could only by supplied by fast gas units. It is this increase in the shares of coal, relative to the shares of gas, which causes higher emissions with flexibility. So, producing an upward shift on the CO_2 emission curves in the factual

case (see Figure 55). A detailed discussion on this effect is given in the next subsection that analyzes the conditions for CO2 offsetting with enhanced flexibility.

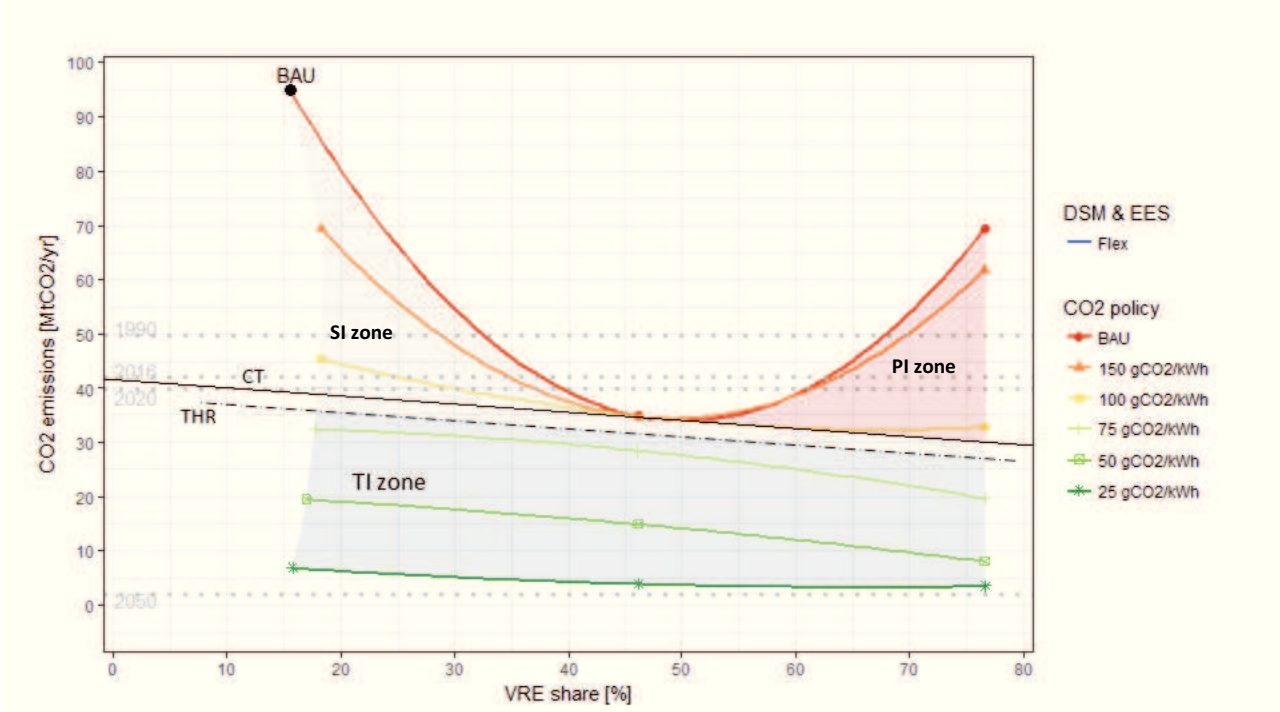


Figure 55. First and second fuel switching with optimal flexibility

In Figure 55 it can also be seen that the common tangent line (i.e., the CT line) is upward shifted and becomes steeper, which enlarges the zone of scrupulous policies. Optimal flexibility places the frontier between scrupulous and pernicious policies at around 90gCO2/KWh instead of 40gCO2/KWh in the counterfactual.

Furthermore, a threshold line (THR) placed slightly below the common tangent line (CT) appears. It denotes an inflection segment from which positive concavity curves are placed over it, and negative concavity curves are places above it. Therefore, the threshold line defines a new frontier inside the zone of scrupulous policies previously defined. It thus delimits the blue zone of Figure 55, which groups the set of thorough intervention (TI zone).

The main existence of the subzone of thorough policies is originated by the role of flexibility in combination with due carbon price signals for integrating variability and reducing emissions. Indeed, optimal flexibility may alter the path of the second fuel switching explained in the counterfactual case provided due carbon policies. As in the counterfactual case, with flexibility, the rebound effect of CO2 emissions is exposed again by the existence

of curves with positive concavity. Similarly, this rebound is explained by a second fuel switching, with a transfer of energy shares from nuclear to gas at moderate VRE penetration (see Figure 56). As previously exposed, this is due to the higher capability of gas-fueled units to effectively integrate variability than nuclear. The arbitration capabilities offered by flexibility, mainly that coming from long-term storage technologies, allows alleviating this rebound by charging during periods of low electricity prices, when there is excess of supply due to VRE infeed, and discharging during peak periods, provided the application of due CO_2 policies. Indeed, as it can be appreciated from Figure 55, this virtuous dynamic of flexibility management is only activated when CO_2 policies are set accordingly, thus, below the threshold line.

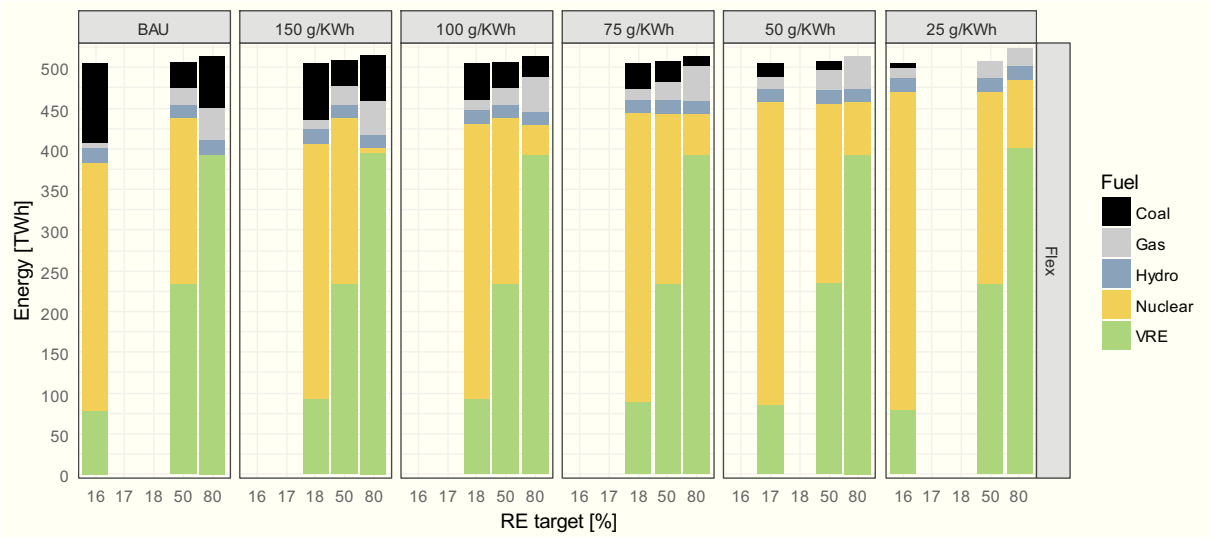


Figure 56. Evolution of energy shares with new flexible technologies

When CO_2 policies are poorly calibrated (i.e., those above the threshold), the CO_2 emissions follow a similar pattern than in the case without storage, so, showing positive concavity and forming a common tangency line. But also, in the case of flexibility under very poor CO_2 policies (i.e., 15 gCO_2/KWh or higher), higher flexibility also benefits mid-load technologies, namely coal, because CO_2 is inadequately evaluated. Thus, the second fuel switching under very poor CO_2 policies might not only comprise a transition from nuclear to gas but also increase the shares of coal, producing very low CO_2 reductions compared to the case with no RPS obligations.

This interaction is not surprising. Flexibility technologies can supply multiple services to the system, one of which is to allow for a smoother utilization of conventional capacity,

improving capacity factors and triggering savings in ramping and wear and tear costs. Thus, physically, the system cannot command storage to only be charged with energy coming exclusively from RE infeed. Imposing such management constraint on storage or DSM would lead to suboptimal flexibility levels and/or an undue utilization of flexibility capabilities contrary to a welfare maximization perspective. Only CO_2 policies can give the correct price signals to increase the marginal value of low-carbon generation, thus, changing the economic interplays during the second fuel switching, so allowing for a virtuous management of flexibility. It is only by implementing proper CO_2 policies (i.e., policies below the threshold) that CO_2 emission levels are strictly decreasing with increasing VRE shares, so, evading the second adverse fuel switching.

c. The impact of flexibility on CO_2 emissions: On the governance of an effective French energy transition by 2050

The previous subsections described the interplays between carbon policies during the enforcement of VRE shares through an RPS. The cases with and without optimal flexibility development were analyzed independently, and the existence of pernicious, scrupulous, and thorough intervention zones were introduced.

Nevertheless, the joint inspection of both cases needs to be considered to unambiguously describe the role of flexibility on the energy transition and decarbonization objectives.

Figure 58 compares the effect of introducing flexibility while applying a regulatory intervention of the form of carbon policies with an RPS. The deployment of flexibility causes an expansion over the CO_2 policy curves.

This expansion may challenge the regular belief that storage and DSM will unequivocally allow for carbon offsetting regardless the regulatory framework in place. The expansion of the CO_2 emission curves is explained by the fact that cost-optimal flexibility from DSM and EES not only serves to more efficiently integrate renewables but also allows for a more efficient utilization of conventional assets regardless their CO_2 content. Thus, flexibility allows VRE to compete with nuclear for baseload supply at low to moderate VRE shares, so, nuclear shares are slightly lower in the case with flexibility. But storage and DSM also reduce the need for peak and extreme peak capacity which is mainly gas fueled. Thus, the peak shaved by load shifting actions would also re-schedule gas-fueled supply episodes to mid-

merit carbon-fueled ones. The same happens with storage arbitration between peak and extreme-peak load, to baseload and mid-merit episodes. If there is excess in VRE infeed before the peak, or at least nuclear power was marginal on the merit order, the energy stored will be carbon-free, and so discharge during the peak. But contrarily, when the marginal capacity before a peak episode is a mid-merit coal unit, the energy stored will be very carbon intensive, so the discharged energy during the peak will be more pollutant than the peaking gas unit it replaces.

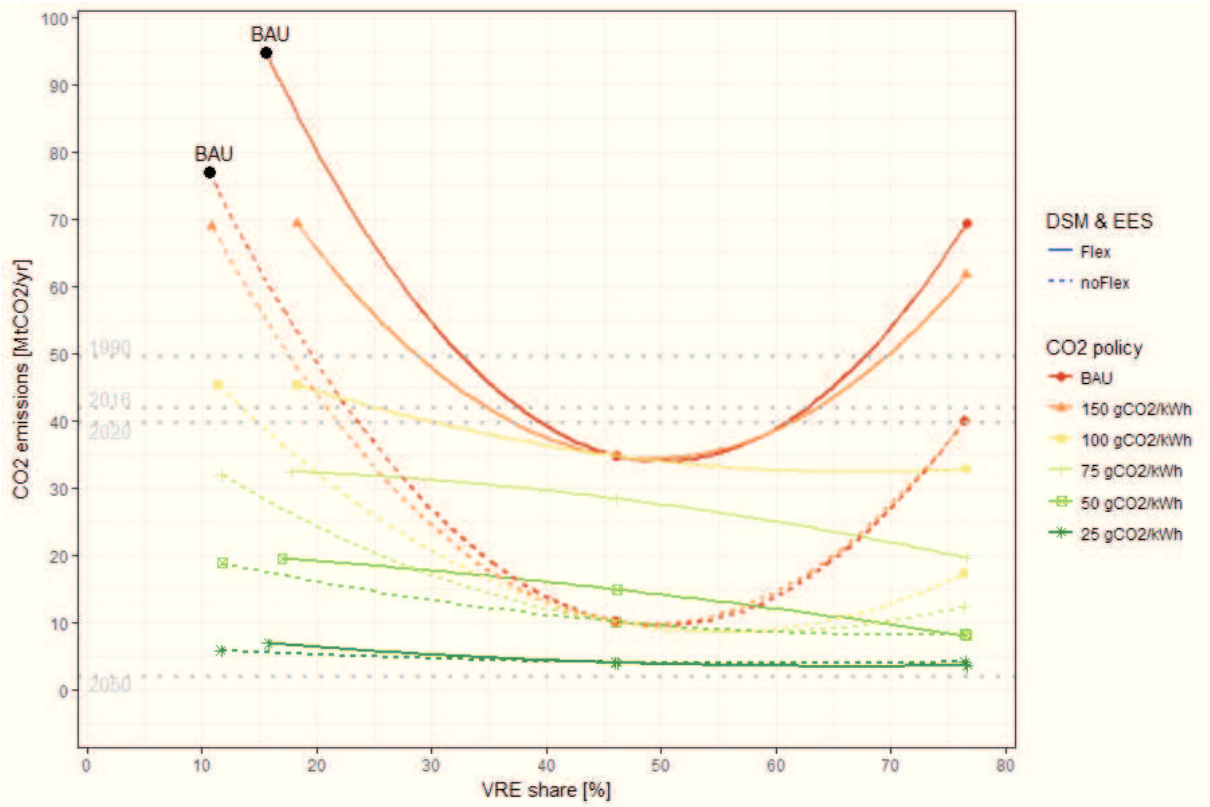


Figure 57. Expansion effect of flexibility over carbon policy curves

Indeed, the arbitrage dynamics of EES and DSM are based on cost and not in CO_2 content. In the absence of a deeply binding CO_2 policy, the optimal flexibility cases lead to higher emission levels than the cases without flexibility, particularly for low to mid shares of VRE. This undesirable mechanism is somehow reduced for mid to high VRE shares because the remaining carbon-intensive conventional capacity is pushed out of the market by the enforcement of the RE shares, so mid-load coal power plants struggler to break-even due to reduced capacity factors. Carbon policies can enable further corrections of the undesirable mechanism too; higher CO_2 penalties would asymmetrically impact the system, reducing the marginal profitability of coal units, so increasing the burden over carbon intensive mid-

load generation technologies, pushing them out of the market. Therefore, a carbon policy and an RPS need to be apprehended as regulatory intervention tools with complementarities, and that should be jointly implemented to effectively produce CO_2 offsetting towards the energy transition.

d. Accurate policy intervention: the conditions for a net CO_2 offsetting with optimal flexibility deployment

As it can be depicted from Figure 58, even by adopting a carbon policy below the level of the threshold (THR), the emission levels resulting from the cases with flexibility might still be considerably higher than in those without it. Only for policies below 75gCO_2/KWh, there is an intersection point before 100% RE shares. But a carbon policy at that level still exhibits a very important gap between the CO_2 emissions when comparing the outcomes with and without flexibility. So, due to the progressive penetration of VRE, the uncertainties related to the regulatory framework affecting the deployment of flexibility, as well as other issues related to information asymmetries, the perception of risk on new investments, among others, adopting a policy with such a huge range of outcomes may affect its effectiveness.

Indeed, it can be misleading to engage in a regulatory intervention for driving a clean energy transition with such an important error on the possible outcomes. In practice, market players may poorly proxy the price signals and delude business opportunities due to inaccurate incentives.

Therefore, it might be convenient to assure some level of accuracy before applying the set of policies. Setting a tolerance margin of the outcome error relative to the emission reduction target would be the upright strategy for assuring an accurate policy.

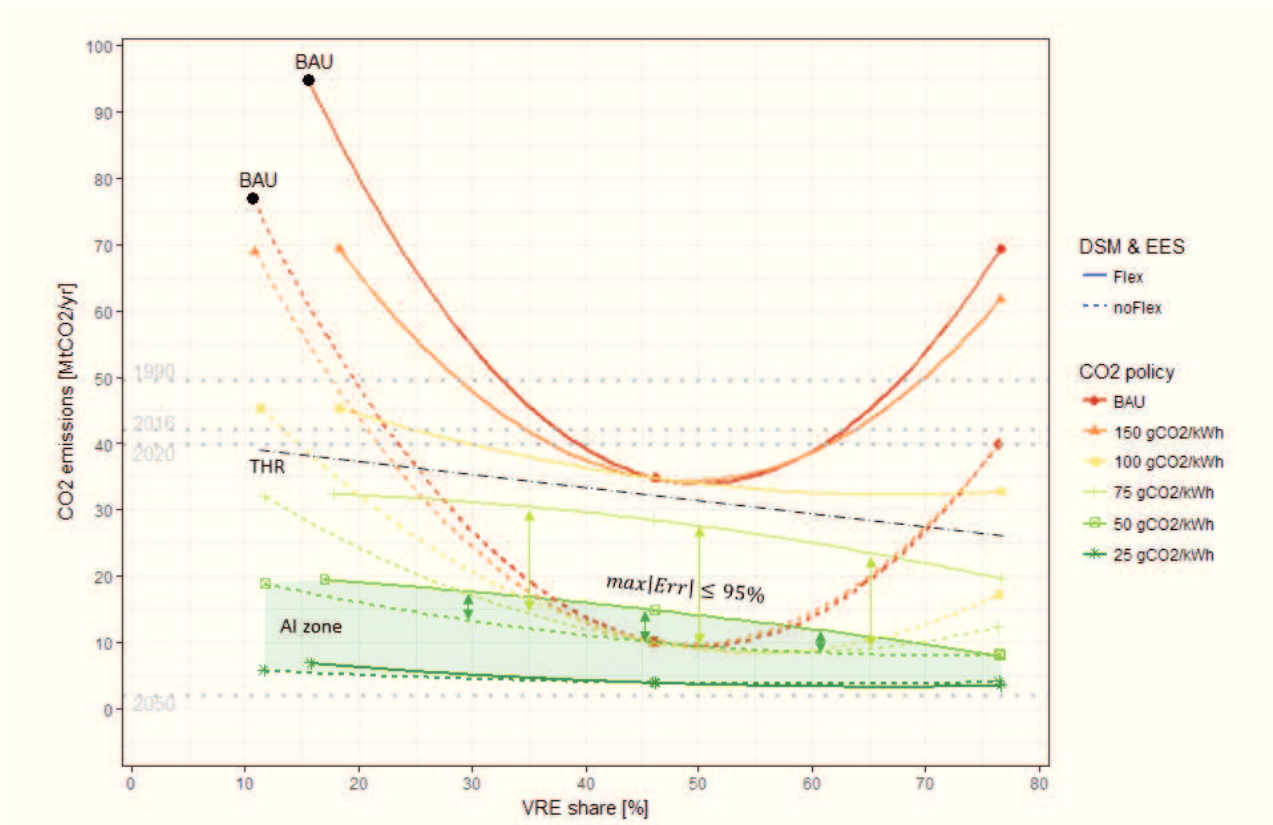


Figure 58. The effect of flexibility on CO2 offsetting

It is convenient to define the outcome error referred to the "BAU" point. By a rapid inspection of Figure 58, it can be seen that the error, computed as the difference on the level of CO2 emissions resulting from curves of similar carbon policy, is also a function of the VRE shares. Thus, to assure the robustness of the intervention, the tolerance margin should be applied in the worst case, which is the point of the maximum gap. Following this reasoning, it is possible to define a set of accurate intervention (AI) by defining a confidence interval (CI) for splitting the thorough intervention zone. Therefore, the interventions belonging to this new zone are simultaneously scrupulous, thorough and accurate.

A formal definition of the accurate intervention zone can be then given by:

$$\left\{ai \in AI \,\middle|\, \forall\, \epsilon > 0\,,\, \exists\, (CO_2\ policy\,, RPS)\,,\, max\left(\frac{CO_{2(vre)}^{Flex} - CO_{2(vre)}^{noFlex}}{CO_{2(vre=BAU)}^{Flex}}\right) \leq \epsilon\right\} \quad (1)$$

Where ϵ is the error margin that can be adjusted to a confidence interval (CI). By setting a 95% CI, the resulting set of accurate interventions is found to be composed by CO2 policies

of 50gCO_2/KWh or lower, regardless the targeted RPS. The accurate intervention set is presented by the green shaded zone of Figure 58. It is worth to be noted that the CI level should be fixed in order to also verify the condition that the resulting AI frontier would be lower or equal than the lowest CO_2 policy belonging to the CT line for the no flexibility case, resulting on the intersection of both zones.

Bringing Pareto-efficiency to the policy debate: On the governance of a cost-efficient energy transition by 2050

This section brings the central figure of any regulatory intervention, namely the total cost it implies. It was previously discussed the fact that BAU points represent the global equilibrium points in the absence of regulatory intervention, thus they might be used as the reference levels over which the cost overruns should be assessed. Furthermore, the both kind of interventions considered, constituted by the carbon policy and the RPS, can be interpreted as policy shocks displacing the equilibrium of the systems to suboptimal states. Therefore, it can be verified that cost overruns resulting from the join implementation of such policies are proportional to the severity of the shock, so, to the rigor imposed through the set of policies considered.

Meanwhile, the case with optimal flexibility has been studied against the counterfactual case in order to highlight its role under different levels of policy intervention. Since both cases are assessed in parallel, the main existence of a difference in the outcomes between them means that investments in new flexibility add value to the system, thus, leading to equilibrium at lower system costs. Hence, the net value of flexibility can be quantified by the net savings it facilitates, thus maximizing the overall welfare.

But the impact of the intervention on costs overruns is not linear and depends on the presence of flexibility. Additionally, the interplays between policies, flexibility and CO_2 offsets were detailed in the previous sections, and the conditions for the existence of an accurate intervention (AI) zone was also introduced. Given that, in the current liberalized context, regulatory intervention through energy policies may only be justified by the decarbonization objectives pretended, two relevant policy questions appear:

1. How much CO_2 emissions should be targeted by the decarbonization objectives? and

2. What is the best set of policies that would allow satisfying such objectives at minimum cost?

Figure 59 presents the outcomes in terms of carbon offsets and cost overruns for every set policy as previously introduced. This figure attempts to give an answer to the first policy question. It highlights the cases representing the cost-optimal development of flexibility in solid lines, against the counterfactual case in dashed lines. It also puts in perspective the extent of the cost overruns caused by the policies. Thus, it can be seen that the cost overruns caused by stringing carbon policies are quite lower than those of produced by the RPS. The first stays in the range of 2 to 5%, with and without flexibility respectively, while the second goes from 5 to nearly 50% depending on the level of the carbon policy and the development of flexibility. As previously introduced, this result is explained by the dominance of nuclear over RE in terms of system-wide marginal abatement costs (MAC) provided the cost assumptions adopted.

Thus, stringing carbon policies mainly causes increasing nuclear shares, on which flexibility determines the additional costs savings for integrating net load variability in a nuclear-dominated power system as exposed in Figure 50 and Figure 51. The cost overruns caused by the enforcement of VRE are also reduced by flexibility. This can be depicted by the overall left shift of the curves of Figure 59 at similar carbon policy levels.

The existence of the different policy zones as explained in the previous sections can also be seen in Figure 59. Decreasing segments group the zones of pernicious policies while increasing ones represent the zones of scrupulous policies. There is only by the strictly increasing path that thorough policies can be identified, while accurate policies can be recognized by strictly increasing colors on which solid and dashed lines are relatively close to each other.

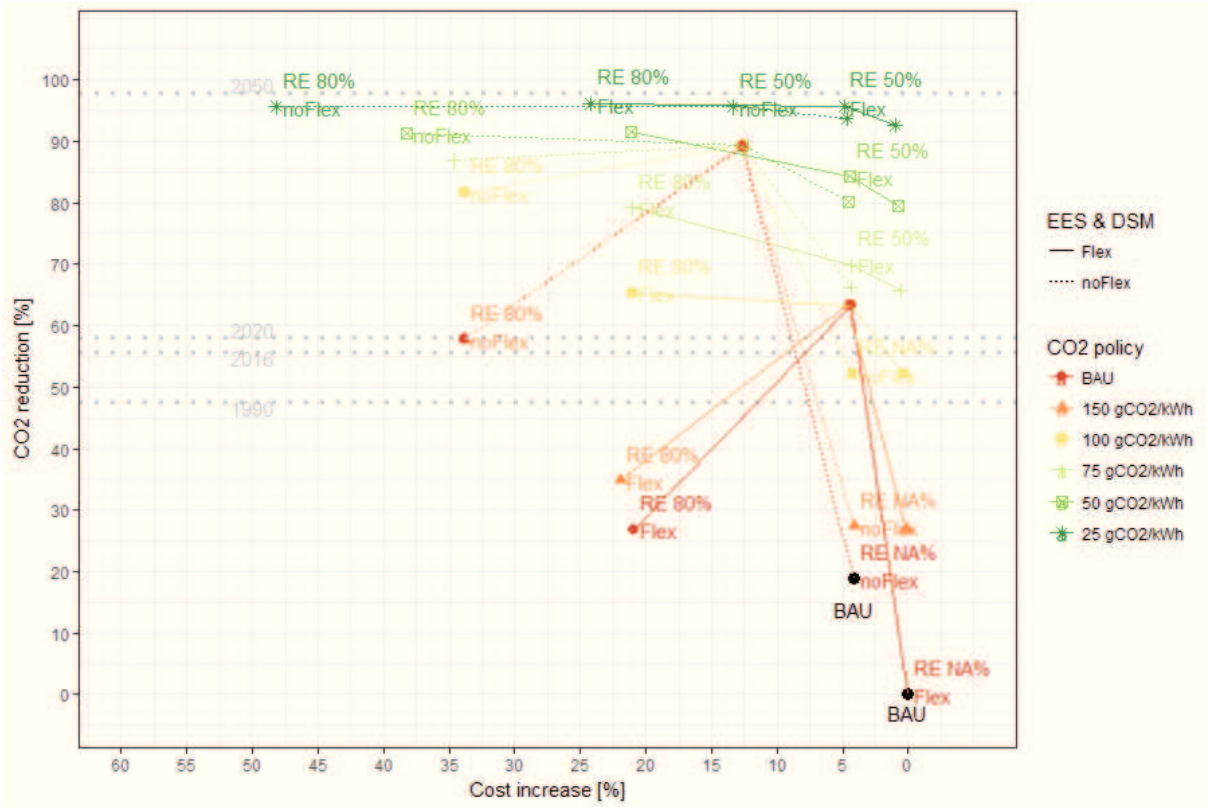


Figure 59. Constellations of constrained equilibrium states

Consequently, by using the CO_2 offsets and the cost increase as the main attributes resulting from the regulatory intervention, it is possible to select the optimal path towards a least-cost deep decarbonization of the French power system subject to the assumptions adopted.

In Figure 60 presents the resulting optimal pathways. Hence, it tries to give an answer to the second question assuming that the 2050 objectives become binding. The solid path of the figure links the optimal points related to the case with flexibility, while the dashed links those corresponding to the counterfactual case. Therefore, the two Pareto fronts define the zone of possible outcomes related to the optimal strategy given the uncertainties dealing with the optimal development of flexibility.

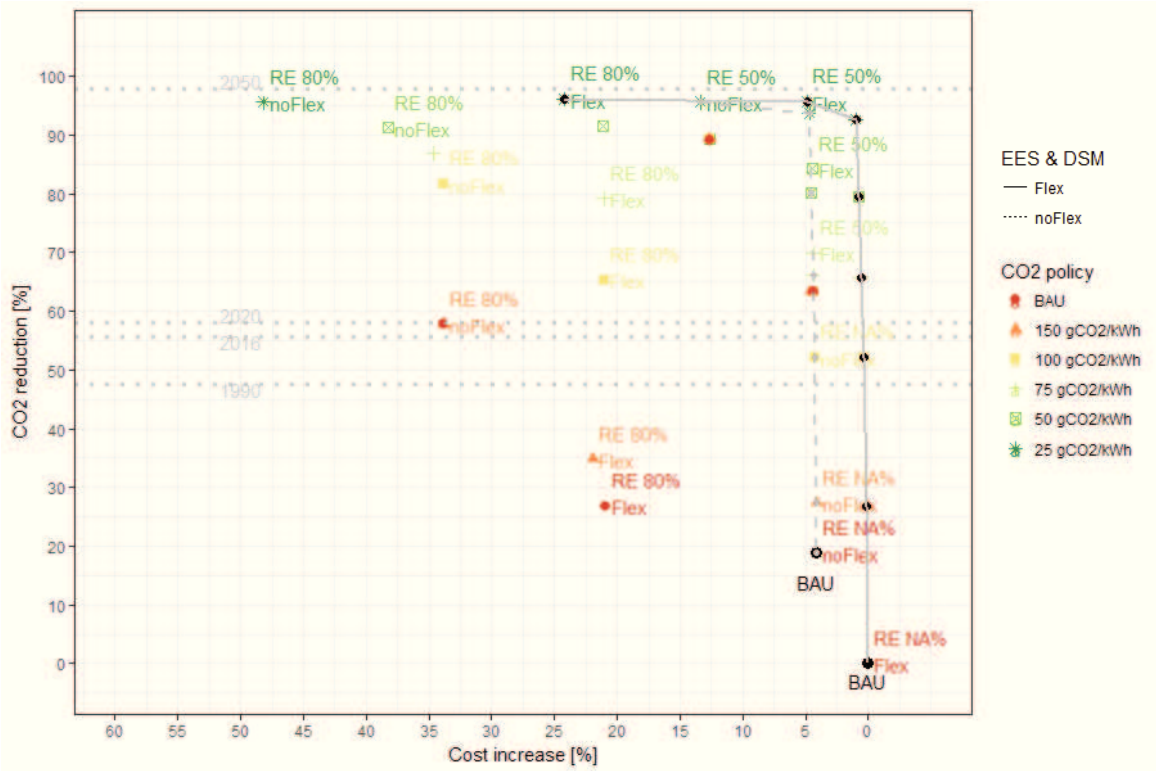


Figure 60. Pareto fronts with and w/o flexibility

3.5. DISCUSSION AND CONCLUSIONS

As it has been commented since the beginning of the chapter, power system planning gives most relevant information to policymakers when it is used to inquiry the main consequences and tradeoffs related to policy oriented decarbonization goals, but not only, proper planning would also consist on analyzing the main rationale of such goals. Thus, power system planning should be conceived as a valuable tool to assure a well-informed definition of decarbonization and energy transition objectives. A necessary condition of proper planning is the use of accurate prospects and detailed modeling frameworks. But also, the adoption of an intelligent procedure to examine the interactions between the relevant factors is required, as well as a skeptical and non-partisan understanding of issues.

In line with the recommendations of the DOE (2006), suggesting that resource planning initiatives should review existing demand response (DR) characterization methods, the DIFLEXO model has been enhanced with a detailed DR module. This has been done by incorporating the DSM categories proposed in the recent study of the Lawrence Berkeley National Laboratory (Alstone et al. 2017).

Considering flexibility on investment planning has been proven compulsory. Demand-side management and storage technologies can add relevant value to the system, particularly when considering stringent constraints due to regulatory intervention. Such effort may also consider the different categories of services that every kind of energy use may deliver. Thus, a bottom-up assessment of the expected deployment of DSM capabilities is necessary, as it is the accurate estimation of cost and operating constraints of storage technologies. Finally, the complementarities between flexibility technologies should also be evaluated by their joint representation on the modeling framework. This seems to be the only adequate alternative for estimating the complete short and long-run interactions between flexibility technologies and the rest of the system.

The comparative view between the cases of cost-optimal development of flexibility against the counterfactual case is particularly valuable when assessing the role of flexibility subject to constraining energy policies. The introduction of contextual figures related to the historic carbon emissions of the French energy mix has proven also valuable for a better understanding of the challenges while defining future decarbonization goals. This is particularly true when considering the evolution of systems with high inertia, as is the case when studying capacity investments, long-term incentives, and regulatory intervention. The French power system is by itself a system that has being intervened with compelling policies since the early 80's.

It has been showed that the main reference point from which the decarbonization goals are set may represent a difference of an order of magnitude on the promoted objectives, hence, altering significantly the severity of the measures that need to be undertaken for their accomplishment. As depicted from Figure 50, if the French power system might be rebuilt by 2050 and similar carbon emissions levels than in 1990 are seek, the "laissez-faire" policy would fail to internalize the decarbonization goals unless a carbon policy may be implemented with a set point of around 75gCO_2/KWh. Such a policy would represent a shock as high as reducing by half the resulting carbon emissions with respect to the business-as-usual (BAU) points (see Figure 50).

Meanwhile, the vision shared among policymakers is to go far beyond the already very low CO_2 emission levels of the 90's. By 2050, the official but not yet mandated target is to achieve a 96% of carbon offsets referred to the levels of 1990. At the same time, the French administration advocates for a profound energy transition by 2050. There is a recent official

study encouraging for a 100% renewable energy mix by 2050 (ADEME 2015). In view of the results previously commented, it can be stated that even if CO2 emissions may be reduced due to stringent carbon policies, a broad energy transition would out of the scope in a "laissez-faire" policy scenario. In addition, by the only means of constraining carbon policies, the shares of unsubsidized RE would not go beyond 24%[126] of the energy shares in the best case (see Figure 50 and Figure 51). So high RE scenarios can only be achieved through an extended and technology-oriented regulatory intervention[127].

Thereafter, the achievement of any goal in terms of ambitious CO2 offsets, and/or higher RE shares, with respect to those obtained under a "laissez-faire" policy (i.e., the "BAU" points of Figure 59) was found to be unavoidably cost increasing. As presented in Figure 59, if significant shares of VRE are enforced, and a CO2 offset in the range of the official goals by 2050 is pretended, cost increases can go up to 25% with optimal flexibility development, and to nearly 48% in the counterfactual case. The cost overruns on every case would depend on the CO2 policy applied, the target of the RPS and the optimal development of flexibility.

Yet, choosing the policies capable of inducing the right incentives, and harmonizing economic-efficiency and decarbonization goals, proves to be very challenging. As presented in Figure 53 and Figure 55, bad calibrated policies may also lead to undesirable results. The frontier separating pernicious, scrupulous, and thorough intervention zones was found to be thin (see Figure 58). Thus, the proper governance of the French energy transition by 2050 must consider the interplays between the three interrelated factors previously presented: a CO2 policy, a conscious and steady technology-oriented intervention, and a supporting regulatory framework dealing with the optimal development of flexibility. It constitutes a triplet of compulsory policies that should be addressed in a coordinated manner to achieve the objectives in a cost-efficient manner. Perhaps the energy trilemma would find an answer trough an intervention trident.

Moreover, current electricity market designs don't fairly reward technologies with very different cost structures, which is the case between low-carbon and fossil fuel technologies. Low-carbon technologies are capital intensive and have negligible marginal costs, while

[126] 24% of RE shares results from adding the maximum of 18% coming from VRE with the remaining 6% of remaining renewables.

[127] This is, by the implementation of RPS, or by applying very stringent CO2 policies together with mandating a nuclear phase-out.

fossil fuel technologies have an opposite cost structure. Hence, in the current context, a profound and cost-efficient energy transition would unavoidably imply a revision of the current market designs.

Decision makers seem to discover these issues in a learning-by-doing basis. They proceed by defining ambitious objectives, implement a set of measures to attain the objectives, and then, realize the cost overruns and the impact that such measures imply, so, end by retiring measures and reviewing policies. In addition, this process of failure and learning is most of the time carried with little criticism. Therefore, any clear long-term signal required for achieving the objectives are either inconsistent or absent. As a result, investors not only lack on incentives, but perceive an enormous regulatory risk on entailing any capital allocation decision due to unsteady, and sometimes incoherent, policies. For the sake of clarity, an important remark needs to be introduced on this point. The issue addressed by the previous description of the current policymaking process is not the commitment on very ambitious goals by itself; it is rather the misinformation and the inaccuracies embracing the whole process, and the lack of coherence on the incentives that are transmitted to the industry. The necessary effort for achieving the mandated goals is rarely duly assessed, neither is it the overall impact of such goals in the broader context. Nonetheless, objectives are seamlessly approved and promoted.

Furthermore, in the current liberalization context, state's regulation is expected to play a minimal role. So, any wide regulatory intervention is perceived by the market under a skeptical eye. As previously discussed, this would be directly the case when targeting ambitious goals related to RE penetration. To achieve such goals the implementation of an RPS seems unavoidable, so, distortive effects might directly appear related to the support mechanism implemented for financing the cost overruns of that policy[128]. But, this would also be indirectly the case when adopting constraining carbon policies, because of the nuclear domination in terms of system-wide marginal abatement costs (MAC), very restrictive CO_2 policies would entail a nuclear push of higher magnitude than that experienced during the 80's. The effects of both kinds of regulatory intervention, directly or

[128] This subject refers to the feed-in tariffs mechanism implemented during the last decade in Europe and in the US. But, other kinds of less market-distortive mechanisms exist for supporting renewables, namely feed-in premiums and price-floors. Nevertheless, the designs of electricity markets would need to significantly evolve to properly manage short-term and long-term interactions if high RE shares are expected to enter the markets.

indirectly, would be traduced by technology-oriented shocks over one or other industry, so clashing with the idea a competitive market driving the long-term decisions.

In the current French context, a reproduction of a comparable intervention policy as that undertaken towards nuclear during the 80's seems very improbable, even if this policy would represent the cost-efficient decarbonization strategy (see Figure 60). In fact, the current French nuclear policy is looking to the opposite direction. The progressive retirement of nuclear capacity is mandated through a nuclear moratorium by 2025 as I was discussed in the previous chapter. Therefore, it seems likely that important compromises will need to be found at two levels: (1) by reconsidering the level of the decarbonization objectives itself, and/or, (2) by evading the cost-efficient path towards decarbonization which involves increasing nuclear shares, so, implementing a second-best strategy which would explicitly cause higher costs. In that sense, the methodology proposed in this study and summarized in Figure 59, offers a meaningful methodology for policymakers concerned with the proper governance of the energy transition through accurate energy policies.

Yet, apart from accurate policies, the success of the French energy transition and the achievement of the decarbonization goals by 2050 will depend on the development of a consistent market design, which should harmonize the long-term signals given by the policies, with the short-term coordination of market players. It will depend as well on the implementation of such policies in the least-distortive manner. These topics will be the subject of further research.

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3.7. APPENDIX

A. UPDATED FORMULATION OF DIFLEXO

Element	Set	Description
t, tt	∈ T	Time slice
d	∈ D	Day of the year
i	∈ I	Supply side generation technologies
con	∈ CON ⊆ I	Conventional generation technologies
re	∈ RE ⊆ I	Renewable energy technologies
vre	∈ VRE ⊆ RE	Subset of variable renewable energy technologies
$non-vre$	∈ nonVRE ⊆ RE	Subset of non-variable renewable energy technologies
ees	∈ EES ⊆ I	Electric energy storage technologies
dr	∈ DR	Demand-response categories (shape, shed, shift, shimmy)
rsv	∈ RSV	Frequency restoration reserve (FRR)
rsv_{up}	∈ RSV_{up} ⊆ RSV	Subset of upward FRR reserve (aFFR+, mFRR+)
rsv_{do}	∈ RSV_{do} ⊆ RSV	Subset of downward FRR reserve (aFFR-, mFRR-)
rsv_a	∈ RSV	Subset of automatic FRR reserve (aFFR+, aFRR-)
rsv_m	∈ RSV	Subset of manual FRR reserve (mFFR+,mFRR-)
rsv_{nsp}	∈ RSV	Subset of non-spinning reserve

Table 23. Sets of DIFLEXO model

Parameter	Unit	Description
t_{slice}	[h]	Time slice considered
$C_i^{Capital}$	[€/GW]	Overnight cost of unit *con, res or ees*

crf_i	[€/GW]	Capacity recovery factor of unit *con*
fc_i	[€/GWh$_{th}$]	Average fuel cost by technology
$o\&m^v{}_{con}$	[€/GWh]	Variable operation and maintenance cost of *con* unit
$o\&m^f{}_{con}$	[€/GW]	Annual fixed operation and maintenance cost of *con* unit
C^{CO2}	[€/ton]	CO_2 cost
ef_i	[tCO_2/GWh]	Emission factor of technology by fuel type
lf_{con}	[€/GW]	Load following cost of unit *con*
$o\&m^v{}_{vre}$	[€/GWh]	Variable operation and maintenance cost of *VRE* unit
$o\&m^f{}_{vre}$	[€/GW]	Annual fixed operation and maintenance cost of *RES* unit
rec_{vre}	[€/GW]	Cost of curtailment of *VRE* unit
$crf^S{}_{vre}$	[€/GW]	Capacity recovery factor of power capacity of *ees* unit
$crf^E{}_{vre}$	[€/GWh]	Capacity recovery factor of energy capacity of *ees* unit
$o\&m^v{}_{ees}$	[€/GWh]	Variable operation and maintenance cost of *ees* unit
$o\&m^f{}_{vre}$	[€/GW]	Annualized fixed operation and maintenance cost of *ees* unit
c^{cr}	[€/GW]	Cost of DR shed
c_{ls}	[€/GW]	Cost of DR shift
δ	[%]	Load variation factor
$G^l{}_{vre,t}{}^{base}$	[GW]	Base year VRE generation of technology VRE on time t
$P_{vre}{}^{base}$	[GW]	Base year VRE capacity installed of technology *res*
$\overline{\eta_{con}}$	[GWhth/GWh]	Full load thermal efficiency of unit con
m_{con}	[-]	Part-load efficiency slope of unit con
b_{con}	[GWh$_{th}$]	Fuel consumption intercept

$\overline{\mathrm{p_{con}}}$	[%]	Maximum power of technology *con* as a function of its installed capacity
$\underline{\mathrm{p_{con}}}$	[%]	Minimum power of technology *con* as a function of its installed capacity
$r^{+}{}_{con}$	[%/min]	Ramp-up capability of technology *con*
$r^{-}{}_{con}$	[%/min]	Ramp-down capability of technology *con*
$\overline{\phi_{ees}}$	[h]	Minimum energy-power ratio of technology *ees*
$\underline{\phi_{ees}}$	[h]	Maximum energy-power ratio of technology *ees*
sd_{ees}	[%/h]	Self-discharge of storage unit *ees*
η_{ees}	[%]	Round cycle efficiency of storage unit *ees*
σ_{ees}	[%]	Fraction of discharge power coming from fuel
$\overline{e_{ees}}$	[%]	Maximum capacity for energy storage of unit *ees*
$\underline{e_{ees}}$	[%]	Minimum capacity for energy storage of unit *ees*
$\overline{s_{ees}}^{ch}$	[%]	Maximum power demand of storage unit *ees* while charging
$\overline{s_{ees}}^{dch}$	[%]	Maximum power supply of storage unit *ees* while charging
t_{rsv_a}	[h]	Minimum required reserve supply duration for aFRR supply
t_{rsv_m}	[h]	Minimum required reserve supply duration for mFRR supply
$t_{peak/off-peak}$	[h]	Hours of the day defining the start of the *peak/off-peak* periods
R	[h]	Number of recovery periods after DR shedding
$L_{hpd}{}^{dr}$	[h]	Time duration a DR can be activated per day
L^{shift}	[h]	Radius of the load shifting window
$P^{Usize}{}_{con}$	[GW]	Unitary size of conventional unit con

ε_l^{rsv}	[%]	Average forecasting RMSE of demand by type of reserve (5% and 1% tolerance for manual and automatic respectively)
ε_{res}^{rsv}	[%]	Average forecasting RMSE of VRE generation (5% and 1% tolerance for manual and automatic respectively)
θ_{res}	[%]	Yearly share of renewable energy (RPS)
$CO_2^{content}$	[gCO2/KWh]	System-wide specific cap on carbon emissions

Table 24. Parameters of DIFLEXO model

Variable	Unit	Description
I_i	[M€]	Annuitized overnight cost of generation unit *i*
$F_{con,t}$	[M€]	Total fuel cost of production unit *con*
$O\&M_{i,t}$	[M€]	Operation and maintenance cost of generation unit *i*
$CO2_{con,t}$	[M€]	CO2 emission cost of conventional unit *con*
$\Delta G_{con,t}$	[M€]	Load following cost of conventional unit *con*
P_i^{inv}	[GW]	New capacity investments of technology *i*
$G^l{}_{con,t}$	[GW]	Generation level of conventional unit *con*
$F_{con,t}$	[GWh$_{th}$]	Linearized part-load fuel consumption of production unit con
$G^l{}_{vre,t}$	[GW]	Generation level of VRE units
$G_{re,t}^l$	[GW]	Generation level of RE units
$G_{vre,t}^{cu}$	[GW]	Power curtailed from V*RE* unit on hour *t*
$G_{vre,t}^{cu,rsv_{do}}$	[GW]	Power curtailed from V*RE* unit on hour *t for downward FRR*
I_{ees}	[M€]	Annuitized overnight cost of storage unit *ees*
$O\&M_{ees,t}$	[M€]	Operation and maintenance cost of *ees* units
S_{ees}^{inv}	[GW]	New power capacity investments of storage technology *ees*

E_{ees}^{inv}	[GW]	New power energy investments of storage technology *ees*
$S_{ees,t}^{ch}$	[GW]	Power demand by storage unit *ees* on time t
$S_{ees,t}^{dch}$	[GW]	Power supply by storage unit *ees* on time t
$E^{l}{}_{ees,t}$	[GW]	Storage level of technology ees
$O\&M_t^{dr}$	[M€]	Operating cost *by Demand Response category*
DR_t^{shed}	[GW]	Demand Response capacity for Load shed
$DR_t^{shift,up/do}$	[GW]	Demand Response capacity for Load shift
$DR_t^{shimmy,up/do}$	[GW]	Demand Response capacity for Load shimmy
$DR_t^{shape,up/do}$	[GW]	Demand Response capacity for Load shape
NL_t	[GW]	Net load on time t
$G_{con,t}^{rsv}$	[GW]	Contribution of *con* units to $mFRR$ up supply
$S_{ees,t}^{ch,rsv}$	[GW]	Contribution of *ees* unit to reserve supply while charging
$S_{ees,t}^{dch,rsv}$	[GW]	Contribution of *ees* unit to reserve supply while discharging
Q_t^{rsv}	[GW]	Reserve required at time *t* by type of *rsv*

Table 25. Variables of DIFLEXO model

Equations of DIFLEXO model

$$
\begin{aligned}
Y = & \sum_{con}(I_{con}) + \sum_{con}\sum_{t}\left(F_{con,t} + O\&M_{con,t} + CO2_{con,t} + \Delta G_{con,t}\right) \\
& + \sum_{vre}(I_{vre}) + \sum_{res}\sum_{t}\left(O\&M_{vre,t} + VREC_{vre,t}\right) \\
& + \sum_{ees}(I_{ees}) + \sum_{ees}\sum_{t}\left(O\&M_{ees,t} + CO2_{ees,t}\right) \\
& + \sum_{dr} I_{dr} + \sum_{dr} O\&M_t^{dr}
\end{aligned}
\tag{1}
$$

Cost related equations:

$$I_i = crf_i \, P_i^{inv} \qquad \forall\, i \neq ees \qquad (2)$$

$$crf_i = \frac{WACC_i \, C_i^{Capital}}{1 - (\frac{1}{1 + WACC_i})^{a_i^{life}}} \qquad \forall\, i \qquad (3)$$

$$I_{ees} = crf^S{}_{ees} \, S_{ees}^{inv} + crf^E{}_{ees} E_{ees}^{inv} \qquad \forall\, ees \qquad (4)$$

$$S_{ees} \underline{\phi_{ees}} \leq E_{ees} \leq S_{ees} \overline{\phi_{ees}} \qquad \forall\, ees \qquad (5)$$

$$I_{dr} = crf_{dr} \; DR_{max}^{dr} \qquad \forall\, dr \qquad (6)$$

$$F_{con,t} = Fuel_{con,t} \, fc_{con} \qquad \forall\, con \qquad (7)$$

$$O\&M_{i,t} = o\&m^v{}_i \; G^l{}_{con,t} + o\&m^f{}_i \, P_i \qquad \forall\, i \qquad (8)$$

$$CO2_{con,t} = C^{CO2} \; ef_{con} \, Fuel_{con,t} \qquad \forall\, con \qquad (9)$$

$$CO2_{ees,t} = C^{CO2} \; \mathrm{ef}_{ees} \, Fuel_{ees,t} \qquad \forall\, t \quad ees \in dCAES \qquad (10)$$

$$\Delta G_{con,t} = \left| G^l{}_{con,t} - G^l{}_{con,t-1} \right| lf_{con} \qquad \forall\, con \qquad (11)$$

$$O\&M_{ees,t} = o\&m^v{}_{ees}\left(S_{ees,t}^{ch} + S_{ees,t}^{dch}\right) + \sigma_{ees} \, S_{ees,t}^{dch} \, fc_{ees} + o\&m^f{}_{ees} \, S_{ees} \qquad \forall\, ees, t \qquad (12)$$

$$Fuel_{con,t} = \left(G^l{}_{con,t} - \overline{p_{con}} \, P_{con} \right) m_{con} + P_{con} \frac{\overline{p_{con}}}{\overline{\eta_{con}}} \qquad \forall\, con \qquad (13)$$

$$m_{con} = \frac{\Delta FC_{con}^{max}}{\Delta P_{con}^{max}} = \frac{\frac{P_{con} \, \overline{p_{con}}}{\overline{\eta_{con}}} - \frac{P_{con} \, \underline{p_{con}}}{\underline{\eta_{con}}}}{P_{con} \, \overline{p_{con}} - P_{con} \, \underline{p_{con}}} = \frac{\frac{\overline{p_{con}}}{\overline{\eta_{con}}} - \frac{\underline{p_{con}}}{\underline{\eta_{con}}}}{\left(\overline{p_{con}} - \underline{p_{con}}\right)} \qquad \forall\, con \qquad (14)$$

$$b_{con} = \left(\frac{\overline{p_{con}}}{\overline{\eta_{con}}} - m_{con}\, \overline{p_{con}} \right) P_{con} \qquad \forall\ con \qquad (15)$$

$$O\&M_t^{dr} = o\&m_{dr}\, DR_t^{dr} \qquad \forall\ t, dr \qquad (16)$$

$$G^l{}_{vre,t} = \frac{G^l{}_{vre,t}{}^{base}}{\overline{P_{vre}{}^{base}}}\ (P_{vre}^{inv}) \qquad \forall\ vre, t \qquad (17)$$

EOM market equilibrium:

$$NL_t = L_t^{base}\,(1+\delta) - \sum_{re=vre} \left(G_{re,t}^l - G_{re,t}^{cu}\right) - \sum_{re=non-vre} \left(G_{re,t}^l\right) \qquad \forall\ t \qquad (18)$$

$$\begin{aligned} NL_t = & \sum_{con} G^l{}_{con,t} + \sum_{ees} \left(S_{ees,t}^{dch} - S_{ees,t}^{ch}\right) \\ & + \sum_t DR_t^{shed} + \sum_{tt=t-L^{shift}}^{tt=t+L^{shift}} DR_{tt,t}^{shift,do} - \sum_t DR_t^{shift,up} \\ & + \sum_{t=24(d-1)+t_{peak}}^{t=24(d-1)+t_{offpeak}} \frac{DR_d^{shape,do}}{12} \\ & - \sum_{t=24(d-1)\,\cup\,24(d-1)+t_{offpeak}}^{t=24(d-1)+t_{peak}\,\cup\,24(d-1)+24} \frac{DR_d^{shape,up}}{12} \end{aligned} \qquad \forall\ d, t \qquad (19)$$

FRR market equilibrium:

$$Q_t^{rsv} = \varepsilon_l^{rsv}\, L_t^{base}\,(1+\delta) + \sum_{vre} \varepsilon_{vre}^{rsv}\, P_{vre} \qquad \forall\ t \qquad (20)$$

$$\sum_{con} \left(G_{con,t}^{rsv_{up}} + G_{con,t}^{rsv_{nsp}}\right) + \sum_{ees} \left(S_{ees,t}^{ch,rsv_{up}} + S_{ees,t}^{dch,rsv_{up}}\right) + DR_t^{shimmy,rsv_{up}} + DR_{t,rsv_{up}}^{shed} = Q_t^{rsv_{up}} \qquad (21)$$

$\forall\ t, rsv_{up}$

$$\sum_{con} G_{con,t}^{rsv_{do}} + \sum_{ees}\left(S_{ees,t}^{ch,rsv_{do}} + S_{ees,t}^{dch,rsv_{do}}\right) + DR_t^{shimmy,rsv_{do}} + G_{wind,t}^{cu,rsv_{do}} = Q_t^{rsv_{do}} \qquad \forall\ t,\ rsv_{do} \qquad (22)$$

Operating constraints of conventional technologies:

$$P_{con} = P_{con}^{inv} \qquad \forall\ con \qquad (23)$$

$$G^l{}_{con,t} + \sum_{rsv_{do}} G_{con,t}^{rsv} \leq \overline{p_{con}} P_{con} \qquad \forall\ con, t \qquad (24)$$

$$\underline{p_{con}} P_{con} \leq G^l{}_{con,t} - \sum_{rsv_{up}} G_{con,t}^{rsv} \qquad \forall\ con, t \qquad \forall\ con, t \qquad (25)$$

$$G^l{}_{con,t} - G^l{}_{con,t-1} + \sum_{rsv_{do}} G_{con,t}^{rsv} \leq r_{con}^{+} G_{con,t}^{l} \qquad \forall\ con, t \qquad \forall\ con, t \qquad (26)$$

$$-r_{con}^{-} G^l{}_{con,t} \leq \Delta G^l{}_{con,t} - G^l{}_{con,t-1} + \sum_{rsv_{up}} G_{con,t}^{rsv} \qquad \forall\ con, t \qquad \forall\ con, t \qquad (27)$$

$$\sum_{rsv_a} G_{con,t}^{rsv} \leq r_{con}^{+} P_{con}^{inv}\ t_{rsv_a} \qquad \forall\ con, t \qquad (28)$$

$$\sum_{rsv_m} G_{con,t}^{rsv} \leq r_{con}^{+} P_{con}^{inv}\ t_{rsv_m} \qquad \forall\ con, t \qquad (29)$$

$$G_{con,t}^{rsv_{nsp}} \leq P_{con}^{inv} - G_{con,t}^{l} \qquad \forall\ con, t, rsv_m \qquad (30)$$

$$H2O_w^l = \frac{H2O_w^{avg}}{\overline{P_{hydro}}} P_{hydro} + \frac{H2O_w^{inflow}}{\overline{P_{hydro}}} P_{hydro} - \sum_{t \in w} Fuel_{hydro,t} \qquad if\ \ w = 1 \qquad (31)$$

$$H2O_w^l - H2O_{w-1}^l = \frac{H2O_w^{inflow}}{\overline{P_{hydro}}} P_{hydro} - \sum_{t \in w} Fuel_{hydro,t} \qquad if\ \ w > 1 \qquad (32)$$

$$\underline{H2O} < H2O_w^l \leq \overline{H2O} \qquad \forall\ w \qquad (33)$$

EES related constraints:

$$E_{ees} = E_{ees}^{inv} \qquad \forall\ ees \qquad (34)$$

$$S_{ees} = S_{ees}^{inv} \qquad \forall\ ees \qquad (35)$$

$$E^l{}_{ees,t} = E^l{}_{ees,t-1}\,(1 - sd_{ees}) + \left(\sqrt{\eta_{ees}}\ S_{ees,t-1}^{ch,} - \frac{S_{ees,t-1}^{dch}}{\sqrt{\eta_{ees}}}\right) t_{slice} \qquad \forall\ t, ees \qquad (36)$$

$$\underline{e_{ees}}\, E_{ees} \leq E^l{}_{ees,t} \leq \overline{e_{ees}}\, E_{ees} \qquad \forall\ t, ees \qquad (37)$$

$$S_{ees,t}^{ch} + \sum_{rsv_{do}} S_{ees,t}^{ch,rsv} \leq S_{ees}\ \overline{s_{ees}}^{ch} \qquad \forall\ t, ees \qquad (38)$$

$$S_{ees,t}^{dch} + \sum_{rsv_{up}} S_{ees,t}^{dch,rsv} \leq S_{ees}\ \overline{s_{ees}}^{dch} \qquad \forall\ t, ees \qquad (39)$$

$$\sum_{rsv_{up}} S_{ees,t}^{ch,rsv} \leq S_{ees,t}^{ch} \qquad \forall\ t, ees \qquad (40)$$

$$\sum_{rsv_{do}} S_{ees,t}^{dch,rsv} \leq S_{ees,t}^{dch} \qquad \forall\ t, ees \qquad (41)$$

$$\left[S_{ees,t}^{ch}\, t_{slice} + S_{ees,t}^{ch,aFRR_{do}}\, t_{rsv_a} + S_{ees,t}^{ch,mFRR_{do}}\, t_{rsv_m}\right]\sqrt{\eta_{ees}} \leq E_{ees} - E^l{}_{ees,t} \qquad \forall\ t, ees \qquad (42)$$

$$\left[S_{ees,t}^{dch}\, t_{slice} + S_{ees,t}^{dch,aFRR_{up}}\, t_{rsv_a} + S_{ees,t}^{dch,mFRR_{up}}\, t_{rsv_m}\right]\frac{1}{\sqrt{\eta_{ees}}} \leq E^l{}_{ees,t} \qquad \forall\ t, ees \qquad (43)$$

$$\left(EES_{ees,t}^{CT} + S_{ees,t}^{dch}\right) \leq S_{ees}\ \overline{s_{ees}}^{dch} \qquad \forall\ t,\ ees \in dCAES \qquad (44)$$

$$Fuel_{ees,t} = \frac{EES_{ees,t}^{CT}}{(1 - E_{ratio})} \qquad \forall\, t,\ ees \in dCAES \qquad (45)$$

Demand response related constraints:

$$0 \le DR_t^{shed} + \sum_{rsv_{up}} DR_t^{shed,rsv} \le DR_{max}^{shed} \qquad \forall\, t \qquad (46)$$

$$\sum_{tt=0}^{R-1} DR_{t,tt}^{shed} \le DR_{max}^{shed}\ L_{hpd}{}^{shed} \qquad \forall\, t \qquad (47)$$

$$DR_t^{shift,up} = \sum_{tt=t-L^{shift}}^{t+L^{shift}} DSM_{t,tt}^{shift,do} \qquad \forall\, t \qquad (48)$$

$$\sum_{t=24(d-1)+1}^{24d} DR_t^{shift,up} \le DR_{max}^{shift}\ L_{hpd}{}^{shift} \qquad \forall\, t \qquad (49)$$

$$\sum_{tt=t-L^{shift}}^{t+L^{shift}} DR_{t,tt}^{shift,do} + \sum_{tt=t-L^{shift}}^{tt=t+L^{shift}} DR_t^{shimmy,rsv_{up}} \le DR_{max}^{shift} \qquad \forall\, t \qquad (50)$$

$$DR_t^{shift,up} + \sum_{tt=t-L^{shift}}^{tt=t+L^{shift}} DR_t^{shimmy,rsv_{do}} \le DR_{max}^{shift} \qquad \forall\, t \qquad (51)$$

$$DR_d^{shape,up} = DR_d^{shape,do} \qquad \forall\, d \qquad (52)$$

$$DR_d^{shape,up} \le DR_{max}^{shape} \qquad \forall\, d \qquad (53)$$

Other flexibility sources:

$$G_{vre,t}^{l} - G_{vre,t}^{cu} - \mathbb{I}_{vre=wind} \sum_{rsv_{do}} G_{wind,t}^{cu,rsv} \le 0 \qquad \forall\, vre \qquad (54)$$

Energy policy constraints

RE shares:

$$\sum_{t} \sum_{con \neq hydro} G^{l}_{con,t} \leq \left(\frac{1-\theta_{re}}{\theta_{re}}\right)\left[\sum_{t} \sum_{re} (G^{l}{}_{re,t} - G^{cu}_{re,t}) + \sum_{t} G^{l}{}_{hydro,t}\right] \qquad (55)$$

CO2 quantity mechanism:

$$\sum_{t} \frac{\left[\sum_{con} Fuel_{con,t}\, ef_{con} + \sum_{ees}\, ef_{ees}\, Fuel_{ees,t}\right]}{L^{base}_{t}\,(1+\delta)} \leq CO_2^{content} \qquad ees = dCAES \qquad (56)$$

B. HYPOTHESIS FOR THE 2050 HORIZON

Technology	*Overnight cost*	*Lifespam*	*crf$_i$*	*O&MV*	*Fuel cost*	*CO_2 content*	*Load following cost*	
	[€/KW]	[yr]	[€/KW yr]	[€/MWh]	[€/MWh]	[t CO_2/MWh]	[€/MW]	***Source***
Nuclear	3750	60	271	2,5	7,0	0,00	55	*JRC - ETRI 2010-2050*
CCGT	785	30	68	4,7	51,7	0,34	20	*IEA / NEA 2015*
CCGT_CCS	1500	30	124	4,0	51,7	0,00	20	*JRC - ETRI 2010-2050*
OCGTadv	545	30	47	6,1	51,7	0,51	15	*IEA / NEA 2015*
flex_ocgt	400	25	56	7,3	51,7	0,64	4,5	*Zerranh & Schill 2015*
Reservoir	2686	80	203	0,0	0,0	0,01	8	*IEA / NEA 2015*
OCOT	490	30	42	7,3	67,3	0,67	10	*IEA / NEA 2015*
Hard_coal	1264	40	102	6,9	19,8	0,96	30	*IEA / NEA 2015*
FBL_CCS	3500	40	269	10,0	11,2	0,13	30	*JRC - ETRI 2010-2050*
PSC_CCS	2550	40	196	3,0	19,8	0,10	30	*JRC - ETRI 2010-2050*

Table 26. Cost of conventional technologies

Technology	*Efficiency*	*pmin*	*pmax*	*ramp_up* [%]	*ramp_down* [%]	*eff_loss*	*m_eff*
Nuclear	37%	1,0	0,4	5%	5%	*0,24*	2,30
CCGT	62%	1,0	0,33	8%	8%	*0,072*	1,51
CCGT_CCS	55%		0,33	8%	8%	*0,072*	1,51
OCGTadv	39%	1,0	0	10%	10%	*0,06*	2,56
flex_ocgt	46%	1,0	0	130%	130%	*0,014*	2,17
Reservoir	90%	1,0	0	20%	20%	*0*	1,11
OCOT	34%	1,0	0	25%	25%	*0,013*	2,94
Hard_coal	47%	1,0	0,38	4%	6%	*0,06*	1,95
FBL_CCS	23%	1,0	0,4	4%	4%	*0,24*	0,27
PSC_CCS	31%	1,0	0,38	4%	6%	*0,06*	1,95

Table 27. Technical parameters of conventional technologies

Technology	*Year*	*Overnight cost* [€/KW]	*Lifespam* [yr]	*crf$_i$* [€/KW yr]	*Source*
Wind	2050	1100	25	96,0	*JRC - ETRI 2010-2050*
PV		710	25	61,8	

Table 28. Cost of renewable technologies

Technology	CAPEX -2050				OPEX -2050			
	System [$/KW]	Battery [$/KWh]	Lifespam [yr]	crf^E [€/KW yr]	crf^S [€/KWh yr]	$o\&m^v$ [€/MWh]	$o\&m^f$ [€/KW]	Source
PHS_new	1 500	68,0	10	28,5 €	- €	- €	6,0 €	
PHS_retro	400	-	10	106,8 €	4,8 €	- €	22,5 €	
Li-ion	140	245,5	10	19,9 €	35,0 €	2,6 €	2,0 €	*JRC - ETRI 2010-2050*
AA-CAES	679	78,8	60	50,9 €	5,9 €	2,0 €	9,5 €	
undCAES	450	26,3	55	32,3 €	1,9 €	1,2 €	5,9 €	
aboCAES	621	42,3	20	44,5 €	3,0 €	1,2 €	1,7 €	
H2-FC	2 465	130,0	8	211,5 €	11,2 €	- €	25,0 €	*Zakeri et Siry, 2015*

Table 29. Cost of energy storage technologies

Technology	EES_Emin [%]	Chg_ramp [% S/h]	Dchg_ramp [% S/h]	Auth_min [h]	Auth_max [h]	Self_dch [% E/h]	Efficiency [%]
PHS	0%	20%	50%	1,00	24	0%	76%
Li-ion	20%	100%	100%	0,25	8	0,0167%	90%
ACAES	0%	13%	13%	1,00	10	0,0004%	70%
DCAES	0%	13%	13%	4,00	24	0,0004%	40%
aboCAES	0%	13%	13%	2,00	4	0,0004%	80%
H2-FC	0%	100%	100%	0,0003	168	0%	85%

Table 30. Technical parameters of conventional technologies

Source	*max capacity* [GW]	*Capital* [k€/MW/an]	*OMV* [€/MWh]	*Duration* [h]	*max_hpd (L_{hpd})* [h]	*Type of DR*
HC_HP	23,4	0	0	0	N/A	shape
LS_hh1	10,3	16,8	0	3	4	shift
LS_hh2	0,8	46,2	0	3	4	
LS_ind_L1	1,2	15	300	108	N/A	
LS_ind_L2	0,8	30	300	108	N/A	
LS_ind_L3	0,8	60	300	108	N/A	
LS_ind_L4	1,0	100	300	108	N/A	shift & shimmy
LS_ind_C1	0,6	20	0	1	2	
LS_ind_C2	0,4	50	0	1	2	
LS_ind_C3	1,0	100	0	1	2	
LS_ind_C4	0,3	150	0	1	2	
LS_ind_C5	0,1	200	0	1	2	

Table 31. Hypothesis related to DR categories. Source: ADEME (2017) and RTE (2017)

C. THE UPTAKE OF NUCLEAR POWER IN FRANCE

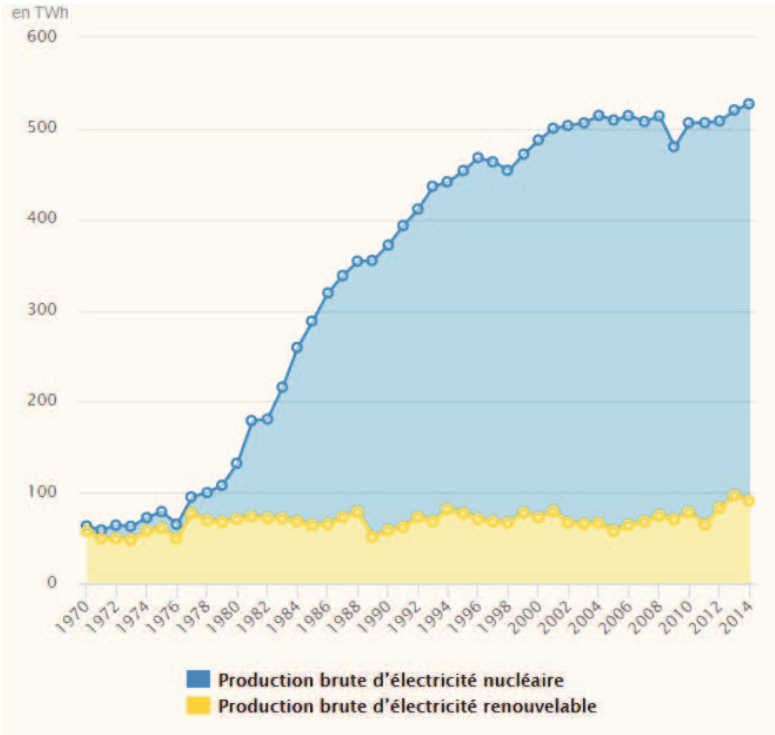

Figure 61. Development of nuclear power in France. Source: MEEDDM, CGDD, SOES

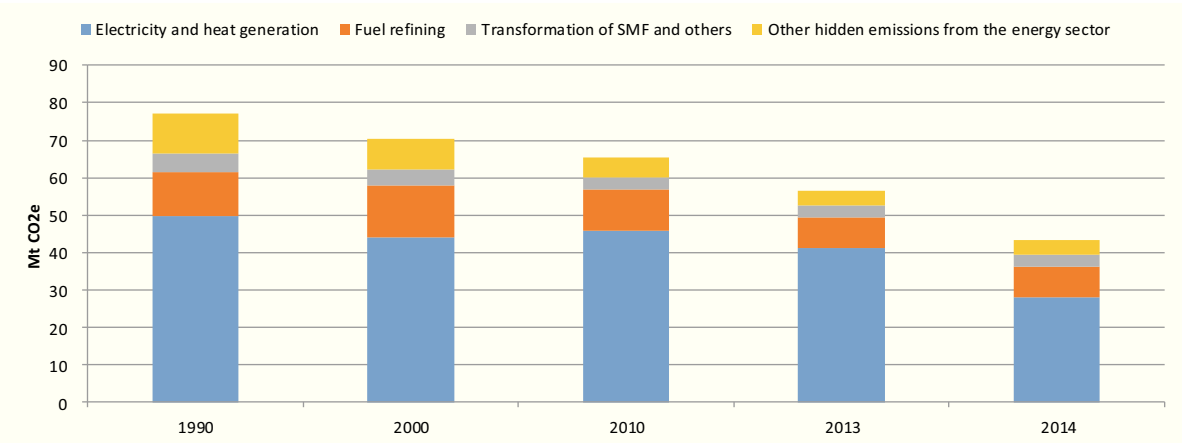

Figure 62. Greenhouse gas emissions of the energy sector in France. Source: Citepa (June 2016).

D. OTHER RESULTS

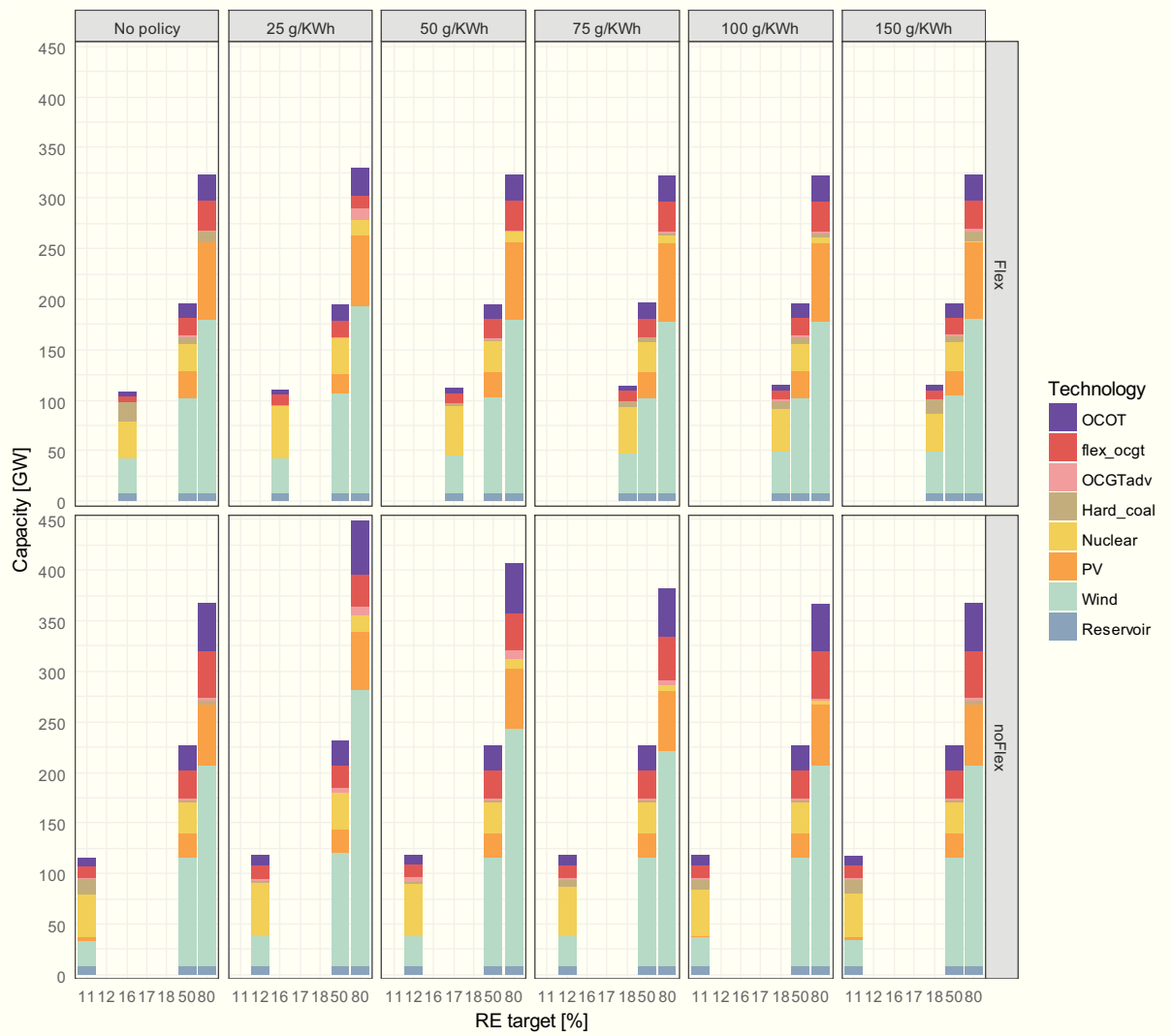

Figure 63. Optimal investments in generation technologies

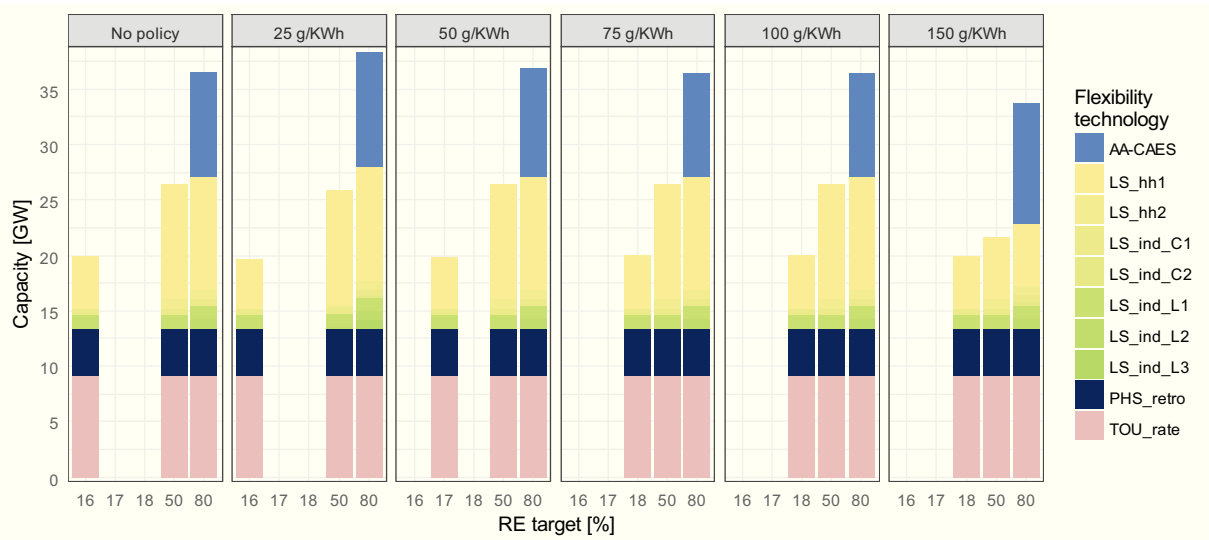

Figure 64. Optimal investments in flexibility technologies

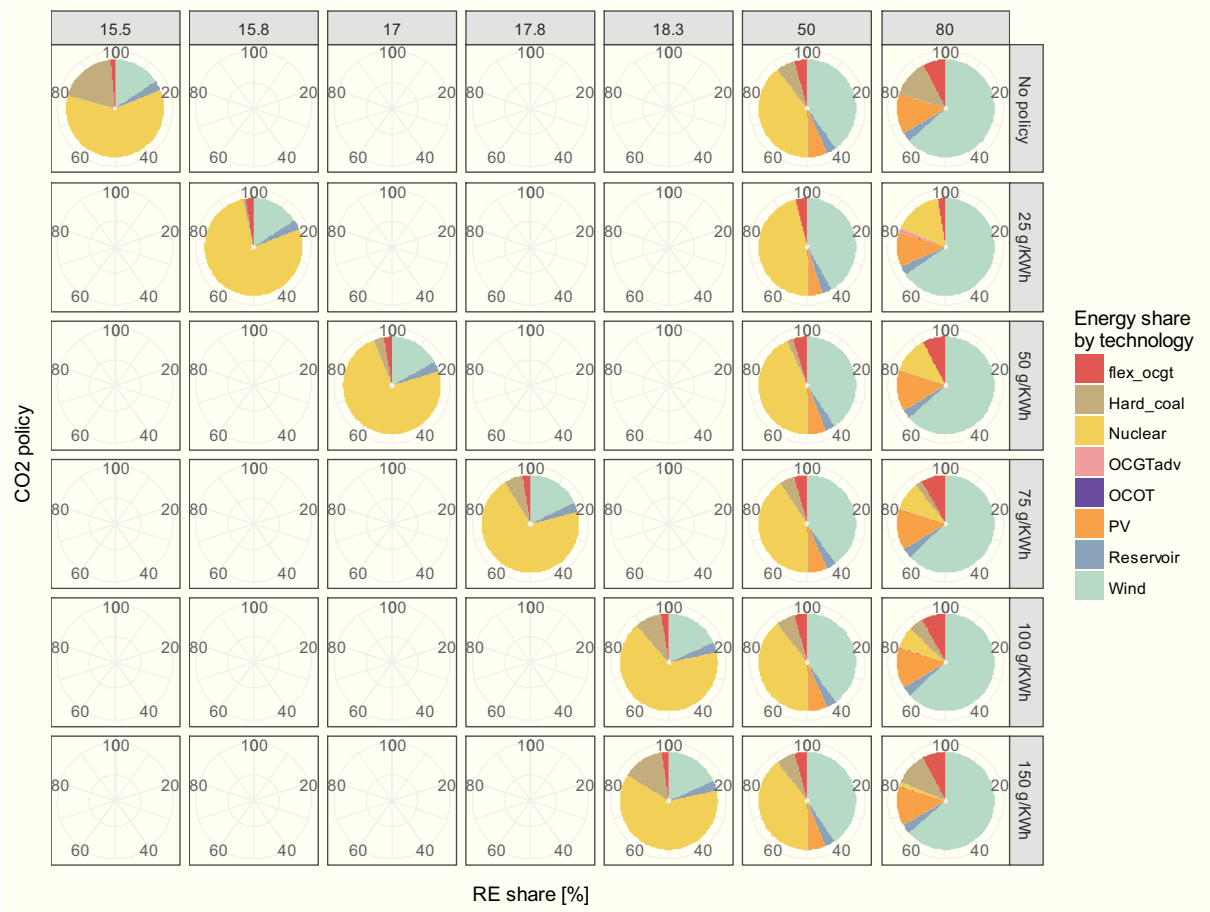

Figure 65. Energy shares on the case where optimal flexibility can be deployed

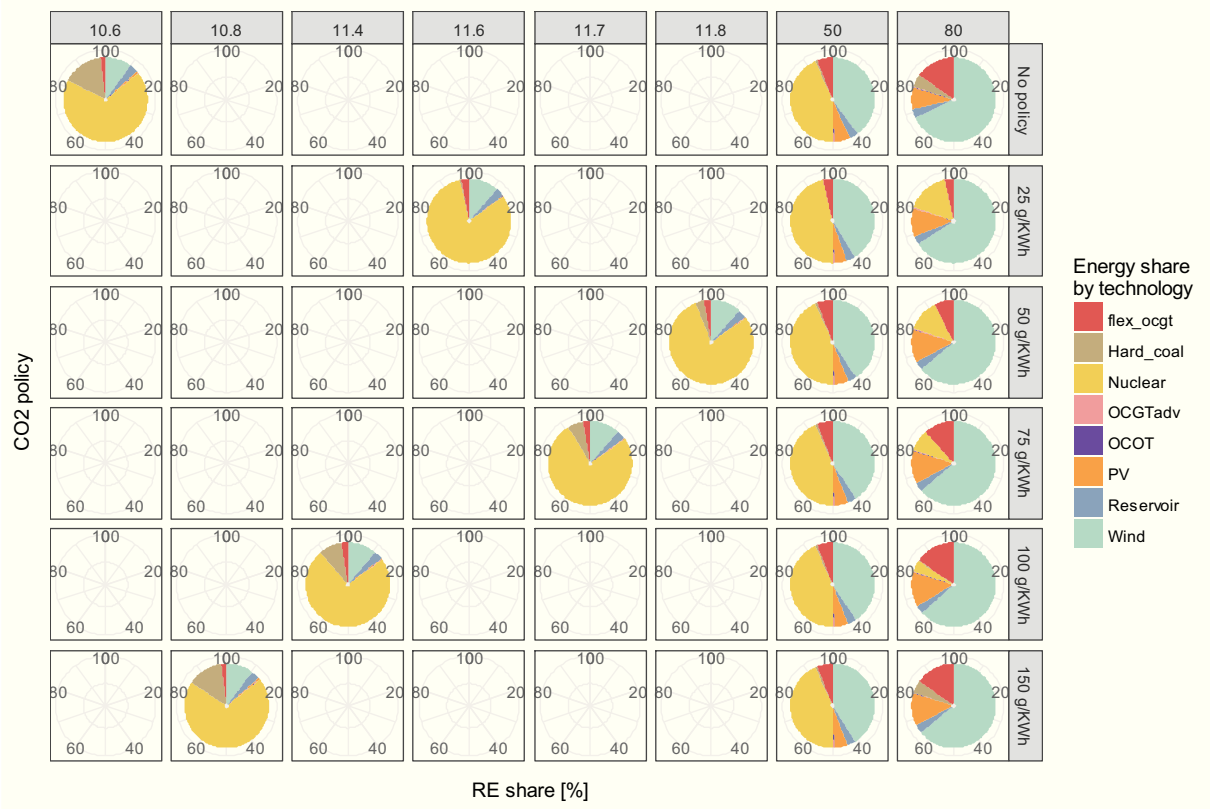

Figure 66. Energy shares on the counterfactual case

Résumé

L'essor des technologies renouvelable à apport variable pose des nombreuses difficultés dans le fonctionnement du système électrique. Ce système doit garantir l'équilibre offre-demande à tout moment, ainsi que d'assurer des hauts niveaux de fiabilité du service. Donc, la variabilité accroit les besoins de flexibilité et des services système. Ils existent plusieurs options capables de fournir ceux services, dont : le renforcement des interconnections, le pilotage intelligent de la demande, le renforcement des capacités de réponse rapide des unités de production, mais aussi, le mis en œuvre des technologies de stockage de l'électricité. Cependant, les marchés électriques actuels sont basés sur la rémunération de l'énergie. Donc, la valorisation intégrale des services qui peut fournir le stockage semble difficile, ce qui restreint le « business case » des options de flexibilité.

Cette thèse s'inscrit autour des propos suivants : (1) modéliser et évaluer les interrelations entre variabilité, besoins de flexibilité et objectifs de décarbonation du parc électrique, (2) analyser le rôle, ainsi que la valeur, des différents technologies du stockage à travers le cas Français aux horizons 2020, 2030 et 2050, et (3) discuter sur les aspects de régulation de la flexibilité, ainsi que proposer des politique énergétiques concrètes permettant la réussite des objectifs de transition énergétique et de décarbonation du mix électrique français.

Abstract

The increasing variability of electricity production in Europe, which is mainly due to the intermittent production of renewables such as wind and photovoltaic (VRE), will require significant efforts to reconcile demand and supply at all times. Thus, increasing shares of variability imply increasing amounts of system services. In addition to upgraded interconnections, demand-side management (DSM) and dispatchable backup capacity, electric energy storage (EES) technologies will have a major role to play in this context.

However, due to the peculiar price formation mechanism prevailing in energy-only electricity markets, the commercial case for EES is being eroded by the very forces that create the need for its increased deployment at the system level. The private incentives of EES are thus diminishing while its social value, which is determined by the multiple system services these technologies can supply, is increasing.

This thesis sets out to (1) model and assess the interplays between variability, flexibility needs and decarbonization objectives, (2) analyze the role and the value of EES technologies in view of the French official objectives by 2020, 2030 and 2050, and (3) discuss regulatory aspects, and propose a set of energy policies allowing to succeed in the energy transition and decarbonization goals.

Mots Clés

Energies renouvelables, Flexibilité, Stockage de l'électricité, Pilotage de la demande, Réseaux intelligents, Investissements

Keywords

Renewable energies, Flexibility, Electricity storage, Demand-response, Smart-grids, Capacity expansion planning, Investments