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Lowering the Financing Cost of Swiss Renewable Energy Infrastructure:

Reducing the Policy Risk Premium and Attracting New Investor Types

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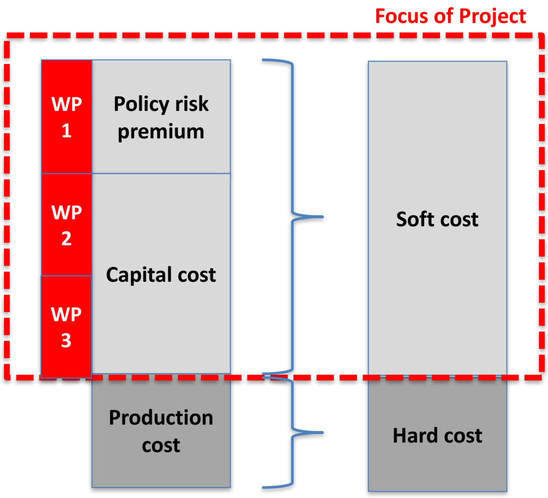
Summary

One of the crucial factors for achieving the objectives of the Swiss Energy Strategy 2050 (ES2050) is to mobilise sufficient amounts of capital to finance renewable energy (RE) projects. As the "hardware cost" of renewable energy technologies, such as wind turbines, has substantially decreased in recent years, the economics of RE projects are increasingly driven by so-called "soft costs". In this project, we have focused on two important elements of soft cost: policy risk and capital cost. Reducing the soft cost of RE investments would allow reaching the ES2050 targets at lower cost to society.



In terms of policy risk (WP1), this project focused on wind power. We identified, categorized and quantified the different components of the policy risk premium required by project developers to make investments in Swiss wind energy projects economically viable. We found that typical complications in the planning and permitting process can increase the cost of an average wind project by 13 to 49 %. In a low risk scenario, this reduces the profitability of a wind project, while in a high risk scenario, it can undermine the economic viability of the investment altogether. If policy targets shall still be achieved in a risky environment, policymakers have a choice to either pay a sufficiently high risk premium or – preferably – reduce policy risk. The biggest risk perceived by wind energy investors in today's policy environment is whether currently developed wind projects will ever receive remuneration under the feed-in tariff scheme. The combination of long permitting procedures and the Energy Strategy 2050's provision to phase out feed-in tariffs after 2022 is a key concern here, as it may put several projects at risk.

The second component of soft cost, capital cost, has been addressed in two different ways. First (WP2), we were interested in understanding what makes Swiss investors decide to finance RE projects either at home or abroad, thinking that reducing the capital outflow to foreign projects might be one way of improving availability of capital for Swiss RE projects. Second (WP3), we investigated the risk-return preferences of existing and new investors in large RE projects, namely electric utilities and institutional investors, to find out whether and under which conditions involving new sources of capital could lower the financing cost of those projects.

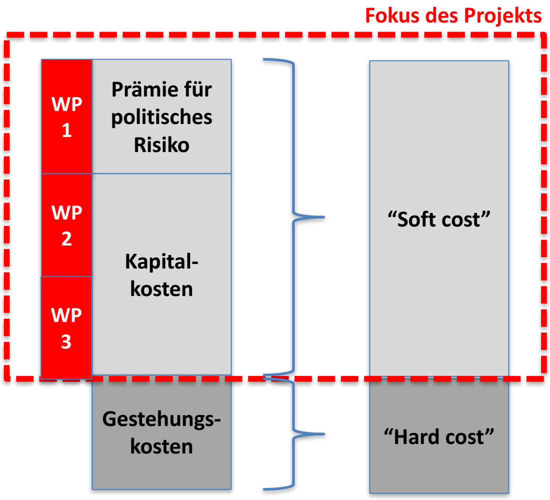
As for the decision to invest at home or abroad, we observed that 70% of the capital provided by Swiss investors is actually invested in energy projects abroad, while only 30% is invested domestically. Based on twenty case studies of Swiss investments in wind and gas-fired power generation projects (2004-2015) at home and abroad, we tried to assess whether this skewed distribution is warranted by the financial performance of different projects. We find that return expectations were higher for foreign gas and wind projects than for domestic RE projects, but an ex-post evaluation of those investment shows that foreign wind projects did not systematically outperform domestic wind projects, and that actual returns for gas projects significantly underperformed wind projects both in Switzerland and abroad. Why would economically rational investors then still not invest larger amounts in domestic projects? One reason might be the illiquidity of the market for Swiss projects, whereas for example in the case of wind energy, many turnkey projects are available for sale in France or Germany. Another possible explanation is that our interviews revealed a lack of systematic comparison between domestic and foreign investments. While investors engage in a quantitative risk assessment for foreign projects, they take a more qualitative approach when investigating the possibility to engage in Swiss projects. There also appears to be a scarcity of systematic comparisons between expected and actual risk-return profiles of energy investments.

In terms of the potential role of institutional investors in financing Swiss RE projects, our focus in WP3 was on hydropower investments. Based on a choice experiment with electric utilities and pension fund managers, we investigated commonalities and differences between those two investor types. While we do not find systematic evidence that including institutional investors would lead to reduced financing cost of RE investments, our results demonstrate some complementarities between utilities and pension funds in that the latter are more averse to taking development and construction risk, which would suggest that institutional investors may be an additional source of (re-)financing existing RE projects if electric utilities are facing capital constraints, whereas the latter have a competitive advantage in dealing with those operational risks. We also show that both utilities and institutional investors are similarly sensitive to electricity price risk, suggesting that policy measures that (partially) shield RE investors from fluctuating electricity prices – such as feed-in tariffs or feed-in premiums – are important facilitators of RE investments: When fully exposed to revenue risk, utilities and pension funds demand a risk premium of 5.98% and 7.94% respectively. Finally, we find evidence for a “birds of a feather flock together” effect – utilities prefer co-investing with other utilities, and the same is true for institutional investors. Exploiting synergies between complementary investor types, therefore, is as much a cultural challenge as it is a financial one, suggesting that policymakers trying to encourage higher levels of institutional investment in renewable energy should not neglect the necessity of enabling measures, such as encouraging dialogue between incumbent and new investors.

The results of our project contribute to an emerging stream of research in energy economics that empirically investigates the current and future determinants of renewable energy investment under policy risk. Our findings show that there is significant scope to lower the soft cost of renewable energy investment and hence improve the risk-return profile of Swiss RE projects. We propose ways of reducing the risk premium for wind energy project development, put the risk-return profile of domestic vs. international investments in perspective, and specify the conditions under which institutional investors can complement traditional energy investors in financing Swiss hydropower. Overall, these evidence-based recommendations should help policymakers to make informed decisions about how to create the necessary conditions for successful implementation of an important element of the Energy Strategy 2050.

Zusammenfassung

Einer der entscheidenden Faktoren für die Erreichung der Ziele der Energiestrategie 2050 (ES2050) ist die ausreichende Bereitstellung von Kapital zur Finanzierung erneuerbarer Energie-Projekte. Da die Kosten erneuerbarer Energietechnologien, wie Windkraftanlagen, in den letzten Jahren deutlich zurückgegangen sind, wird die Wirtschaftlichkeit erneuerbarer Energie-Projekte zunehmend durch so genannte „Soft Costs“ bestimmt. Im vorliegenden Projekt standen zwei wesentliche Elemente dieser „Soft Costs“ im Vordergrund: die Prämie für politisches Risiko und die Kapitalkosten. Die Verringerung der „Soft Costs“ von Investitionen in erneuerbare Energien würde es ermöglichen, die Ziele der Energiestrategie mit niedrigeren gesellschaftlichen Kosten zu erreichen.



Im Hinblick auf das politische Risiko (WP1) konzentrierte sich dieses Projekt auf die Windenergie. Ziel war die Identifikation, Kategorisierung und Quantifizierung der verschiedenen Komponenten einer angemessenen Risikoprämie, um Investitionen in Schweizer Windenergieprojekte wirtschaftlich zu gestalten. Typische Komplikationen im Planungs- und Genehmigungsprozess können die Kosten eines durchschnittlichen Windprojekts um 13 bis 49% erhöhen. In einem Szenario mit relativ geringen Risiken reduziert dies die Rentabilität eines Windprojekts, während es in einem Hochrisikoszenario die Wirtschaftlichkeit der Investition insgesamt untergraben kann. Sollen politische Ziele auch in einem risikobehafteten Umfeld erreicht werden, stehen politische Entscheidungsträger vor der Wahl, entweder eine ausreichend hohe Risikoprämie zu zahlen oder – vorzugsweise – das Problem an der Wurzel zu packen und politische Risiken zu reduzieren. Das grösste Risiko, das von Windenergie-Investoren im aktuellen politischen Umfeld wahrgenommen wird, ist die Frage, ob derzeit in der Entwicklung befindliche Windprojekte dereinst in den Genuss von Einspeisevergütungen kommen werden. Eine zentrale Herausforderung stellt die Kombination aus langwierigen Genehmigungsverfahren und dem gemäss Energiestrategie 2050 vorgesehenen Auslaufen des heutigen Fördersystems nach 2022 dar. Dies könnte die Realisierung zahlreicher Windenergie-Investitionen gefährden.

Die zweite Komponente der „Soft Costs“, die Kapitalkosten, wurden im vorliegenden Projekt in zweierlei Hinsicht untersucht. Erstens (WP2) untersuchten wir den Entscheidungsprozess Schweizer Investoren im Hinblick auf in- versus ausländische Energieprojekte – dies im Hinblick darauf, dass die Verringerung des Kapitalabflusses ins Ausland die Kapitalverfügbarkeit für Schweizer erneuerbare Energie-Projekte verbessern könnte. Zweitens (WP3) untersuchten wir die Risiko-Rendite-Präferenzen bestehender und neuer Investoren in erneuerbare Energien, um herauszufinden ob und unter welchen Bedingungen der Einbezug institutioneller Investoren die Finanzierungskosten inländischer Projekte senken könnte.

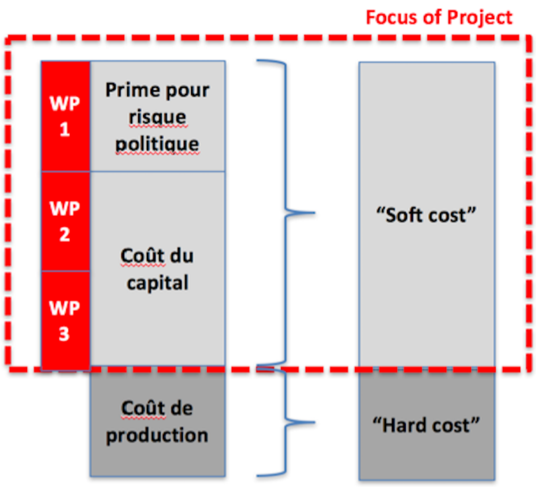
Bezüglich der Entscheidung, im In- oder Ausland zu investieren, haben wir festgestellt, dass 70% des von Schweizer Investoren bereitgestellten Kapitals in Energieprojekte im Ausland fliesst, während nur 30% im Inland investiert werden. Basierend auf 20 Fallstudien von Schweizer Investitionen in Wind- und Gas-Kraftwerksprojekte (2004-2015) im In- und Ausland haben wir versucht zu beurteilen, ob diese Verteilung durch eine systematisch bessere finanzielle Performance der Auslandsinvestitionen gerechtfertigt ist. Es zeigt sich, dass die Renditeerwartungen für ausländische Gas- und Windprojekte höher waren als für inländische Projekte, eine Ex-Post-Analyse der getätigten Investitionen zeigt jedoch, dass die finanzielle Performance ausländischer Windkraftwerke nicht systematisch besser ist als jene inländischer Windkraftwerke, und dass die tatsächlich erzielten Renditen von Investitionen in Gaskraftwerke deutlich hinter denen von in- und ausländischen Investitionen in Windenergie zurückbleiben. Was würde angesichts dieser Datenlage wirtschaftlich rationale Investoren davon abhalten, grössere Beträge in inländische Projekte zu investieren? Eine Erklärung könnte die mangelnde Liquidität des Marktes für Investitionen in der Schweiz sein, während zum Beispiel viele schlüsselfertige Windenergie-Projekte in Frankreich oder Deutschland verfügbar sind. Die durchgeführten Interviews deuten zudem darauf hin, dass die Investoren in vielen Fällen keinen systematischen Vergleich zwischen in- und ausländischen Investitionen vornehmen. Während für ausländische Projekte eine quantitative Risikobewertung durchgeführt wird, verfolgen die Investoren bei der Beurteilung von Schweizer Projekten häufig einen qualitativen Ansatz. Desweiteren besteht ein Mangel an systematischen Vergleichen zwischen erwarteten und tatsächlichen Risiko-Rendite-Profilen der getätigten Energieinvestitionen.

Im Hinblick auf die potenzielle Rolle institutioneller Investoren bei der Finanzierung von Schweizer Energieprojekten lag der Fokus von WP3 auf Wasserkraftwerken. Auf der Grundlage von Wahlexperimenten mit Elektrizitätsversorgern und Pensionskassenmanagern untersuchten wir Gemeinsamkeiten und Unterschiede zwischen diesen beiden Investorentypen. Während wir keine systematischen Belege dafür finden, dass institutionelle Anleger zu tieferen Finanzierungskosten von Investitionen in erneuerbare Energien führen würden, zeigen unsere Ergebnisse einige Komplementaritäten zwischen EVU und Pensionskassen. Letztere reagieren sensibler auf Entwicklungs- und Baurisiken, was darauf hindeutet, dass institutionelle Anleger primär eine zusätzliche Quelle für die (Re-)Finanzierung bestehender Kraftwerke sein können. Dies kann einen Beitrag zur Finanzierungslücke leisten, die durch Liquiditätsprobleme einiger Elektrizitätsversorger entsteht. Letztere wiederum haben einen Wettbewerbsvorteil, wenn es darum geht, operative Risiken zu managen. Sowohl EVU als auch institutionelle Anleger reagieren empfindlich auf das Strompreisrisiko, was darauf hindeutet, dass politische Maßnahmen, die Energieinvestoren ganz oder teilweise gegen schwankende Strompreise absichern (z. B. Einspeisetarife oder Einspeiseprämien) Investitionen in erneuerbare Energieprojekte wirksam erleichtern. Wenn sie dem vollen Strompreisrisiko ausgesetzt sind, verlangen EVU und Pensionskassen eine Risikoprämie von 5.98% bzw. 7.94%. Schliesslich finden wir Anzeichen eines „Gleich und gleich gesellt sich gern“-Effekts: Energieversorger bevorzugen Co-Investitionen mit anderen EVU, und das gleiche gilt für institutionelle Investoren. Das Erzielen möglicher Synergien zwischen komplementären Investoren ist daher nicht nur eine finanzielle Frage, sondern in mindestens ebenso grossem Ausmass eine kulturelle Herausforderung. Politische Entscheidungsträger, die sich ein verstärktes Engagement institutioneller Investoren im Bereich erneuerbarer Energien wünschen, sollten darum auch Massnahmen zur Förderung des Dialogs zwischen verschiedenen Investoren ergreifen.

Die Ergebnisse unseres Projekts tragen zu einem aktuellen Gebiet der energiewirtschaftlichen Forschung bei, nämlich der empirischen Analyse der Bestimmungsfaktoren erneuerbarer Energie-Investitionen unter politischer Unsicherheit. Unsere Analysen zeigen, dass ein erhebliches Potenzial zur Senkung der „Soft Costs“ von Investitionen in Schweizer erneuerbare Energie-Projekte, und damit zur Verbesserung des Risiko-Rendite-Profils dieser Investitionen, besteht. Der vorliegende Bericht formuliert konkrete Vorschläge zur Senkung der Risikoprämie für Windenergie-Investitionen, erlaubt einen angemessenen Vergleich des Risiko-Rendite-Profils inländischer und ausländischer Energie-Investitionen, und zeigt auf, unter welchen Bedingungen institutionelle Investoren traditionelle EVU bei der Finanzierung der Schweizer Wasserkraft ergänzen können. Mit diesen evidenzbasierten Empfehlungen leistet der Bericht einen fundierten Beitrag zur Umsetzung eines wichtigen Elements der Energiestrategie 2050, der Mobilisierung von Investitionen in eine ausreichende und kostengünstige Versorgung mit einheimischen erneuerbaren Energien.

Résumé

L'un des facteurs les plus importants pour atteindre les objectifs de la Stratégie énergétique suisse 2050 (SE2050), est de mobiliser des fonds suffisants pour financer des projets d'énergie renouvelable (EnR). Comme le prix des technologies utilisées pour les énergies renouvelables, tel que les éoliennes, a considérablement diminué ces dernières années, l'économie des projets EnR est de plus en plus motivée par les coûts accessoires ou « soft costs ». Dans ce projet, nous nous sommes concentrés sur deux éléments importants des coûts accessoires: risque politique et coût du capital. Réduire les coûts accessoires des investissements EnR permettrait d'atteindre les objectifs de la SE2050 à moindre coût pour la société.



En termes de risque politique (WP1), ce projet se concentre sur les éoliennes. Nous avons identifié, catégorisé et quantifié les différents éléments de la prime de risque politique, exigée par les promoteurs de projets, pour rendre les investissements dans des projets d'énergie éolienne suisses économiquement rentables. Nous avons constaté que les complications typiques dans la planification et le processus d'autorisation peuvent augmenter le coût d'un projet éolien moyen de 13 à 49%. Dans un scénario à faible risque, cela réduit la rentabilité d'un projet éolien, alors que dans un scénario à risque élevé, cela peut complètement compromettre la rentabilité économique de l'investissement. Si les objectifs politiques devraient cependant être atteints dans un environnement à risque, les législateurs ont le choix soit de payer une prime de risque suffisamment élevée, soit, de préférence, de réduire les risques politiques. Dans l'environnement politique actuel, le plus grand risque perçu par ceux investissant dans les énergies éoliennes, est de savoir si les projets éoliens développés actuellement recevront une rémunération dans le cadre du système de rétribution de l'injection. La combinaison des longues procédures de délivrance de permis et de la disposition de la Stratégie énergétique 2050 d'éliminer les rétributions après 2022, est une préoccupation majeure ici, car elle risque de mettre en danger plusieurs projets.

Le deuxième élément des coûts accessoires, le coût du capital, a été abordé de deux manières différentes. Tout d'abord (WP2), nous avons été intéressés de comprendre ce qui incite les investisseurs suisses à financer des projets dans les énergies renouvelables, soit à la maison, soit à l'étranger, en pensant que la réduction des flux de capitaux vers des projets étrangers pourrait être une façon d'améliorer la disponibilité de capitaux pour les projets d'énergies renouvelables en Suisse. Deuxièmement (WP3), nous avons étudié les préférences du rapport risque-rendement des investisseurs existants, ainsi que des nouveaux, dans les grands projets EnR, à savoir les services publics d'électricité et les investisseurs institutionnels, pour déterminer si et dans quelles conditions, utiliser de nouvelles sources de capitaux pourrait réduire le coût de financement de ces projets.

En ce qui concerne la décision d'investir au niveau national ou à l'étranger, nous avons observé que 70% du capital fourni par les investisseurs suisses est réellement investi dans des projets énergétiques à l'étranger, alors que seulement 30% sont investis au niveau national. Sur la base de vingt études de cas d'investissements suisses dans des projets de production d'énergie éolienne et de centrales à gaz (2004-2015), à domicile et à l'étranger, nous avons essayé d'évaluer si cette répartition inégale est justifiée par la performance financière des différents projets. Nos résultats indiquent que les attentes en matière de rendement étaient plus élevées pour les projets gaziers et éoliens étrangers que pour les projets au niveau domestique, mais une évaluation a posteriori de ces investissements montre que les projets éoliens à l'étranger ne surpassaient pas systématiquement les projets éoliens nationaux et que les rendements réels des projets de gaz étaient considérablement inférieurs aux projets éoliens en Suisse et à l'étranger. Pourquoi alors des investisseurs économiquement rationnels n'investiraient pas d'avantage dans des projets nationaux? Une des raisons pourrait être un manque de liquidité du marché pour des projets suisses, alors que par exemple, dans le cas de l'énergie éolienne, de nombreux projets clés en main sont disponibles en France ou en Allemagne. D'autre part, nos entretiens ont révélé un manque de comparaison systématique entre les investissements nationaux et étrangers, qui pourrait être une autre explication possible. Alors que les investisseurs s'engagent dans une évaluation quantitative des risques pour les projets étrangers, ils adoptent une approche plus qualitative lorsqu'ils étudient la possibilité de s'engager dans des projets suisses. Il semble également y avoir un manque de comparaisons systématiques entre les profils de risque-rendement attendus et ceux réels des investissements énergétiques.

En ce qui concerne le rôle potentiel des investisseurs institutionnels dans le financement des projets suisses d'énergie renouvelable, notre attention dans WP3 était sur les investissements hydroélectriques. Sur la base d'expérimentation de choix avec les compagnies d'électricité et les gestionnaires de fonds de pension, nous avons étudié les points communs et les différences entre ces deux types d'investisseurs. Bien que nous ne trouvions pas de preuves systématiques que l'inclusion des investisseurs institutionnels entraînerait une réduction du coût de financement des investissements dans les énergies renouvelables, nos résultats démontrent certaines complémentarités entre les services publics et les caisses de retraite dans le sens que ces dernières ont une plus grande aversion à prendre des risques au niveau du développement et de la construction. Cela suggère que les investisseurs institutionnels pourraient constituer une source supplémentaire de (refinancement) de projets d'énergie renouvelable existants, dans le cas où les services d'électricité sont confrontés à des contraintes de capital, alors que derniers ont un avantage concurrentiel pour faire face à ces risques opérationnels. Nous montrons aussi que les services publics et les investisseurs institutionnels sont également sensibles aux risques lié aux changements du prix de l'électricité, ce qui suggère que les mesures politiques qui (partiellement) protègent les investisseurs des fluctuations du prix de l'électricité - tels que les tarifs de rachat ou les primes de rachat - sont des facteurs importants d'investissements dans les EnR: lorsqu'ils sont pleinement exposés au risque lié au revenu, les services publics et les fonds de pension exigent une prime de risque de 5,98% et 7,94% respectivement. Enfin, nous trouvons des preuves d'un effet « qui se ressemble, s'assemble » - les services publics préfèrent co-investir avec d'autres services publics, et il en va de même pour les investisseurs institutionnels. L'exploitation de synergies entre des types complémentaires d'investisseurs est donc autant un défi culturel que financier, ce qui suggère que les législateurs, tentant d'encourager des investissements institutionnels plus élevés dans les énergies renouvelables, ne devraient pas négliger la nécessité de prendre des mesures, tel que d'encourager le dialogue entre les investisseurs titulaires et les nouveaux investisseurs.

Les résultats de notre projet contribuent à une nouvelle génération de recherches dans l'économie de l'énergie qui étudie de manière empirique, les déterminants actuels et futurs des investissements dans les énergies renouvelables, dans le cadre de risques politiques. Nos résultats montrent qu'il existe une marge de manœuvre importante afin de réduire le coût accessoire des investissements dans les énergies renouvelables et donc d'améliorer le profil risque-rendement des projets suisse dans les EnR. Nous proposons des moyens de réduire la prime de risque pour le développement de projets d'énergie éolienne, de mettre en perspective le profil risque-rendement des investissements nationaux versus ceux des investissements internationaux, et de préciser les conditions dans lesquelles les investisseurs institutionnels peuvent compléter les investisseurs énergétiques traditionnels dans le financement de l'hydroélectricité suisse. Dans l'ensemble, ces recommandations fondées sur des données factuelles devraient aider les législateurs à faire des choix éclairés sur la façon de créer les conditions nécessaires à une mise en œuvre réussie d'un élément clé de la Stratégie énergétique 2050.

WP 1: Quantifying and Reducing the Policy Risk Premium of Wind Energy Projects in Switzerland

Abstract

Long and complex administrative processes are one of the main areas of concern in wind energy development both in Switzerland and internationally. The pre-construction stage of a wind energy project in Switzerland stretches to about a decade, which is more than twice as long as the European average of 4.5 years. WP1 characterizes the process of obtaining necessary zoning and interconnection permits in Switzerland and provides an estimation of related costs. The data have been gathered through 22 confidential interviews with project developers and more than ten cantonal permitting agencies, as well as a review of regulatory documents. Since the administrative procedures vary by canton, we created an overview of the different cantonal planning approaches. We divided cantons into three groups, depending on the extent that wind energy had been integrated into the cantonal regulatory framework.

Furthermore, WP1 quantifies the risk premium faced by the project developer due to regulatory bottlenecks. A discounted cash flow model was built to compare the profitability indicators (IRR, NPV) and the levelized cost of electricity (LCOE) of the reference case to the scenarios with administrative and policy risks. The scenarios included situations when the project is delayed due to restrictions, experiences planning cost overruns or lower capacity factor, or has fewer turbines permitted than were originally planned. The highest profitability risks are related to availability of KEV (feed-in tariff) payments. The model has confirmed that due to low electricity price levels, no wind project is currently profitable without KEV. Significant losses of profitability occur when the project's capacity factor is reduced or the project gets downsized and fewer turbines than originally planned are permitted. These findings illustrate a significant policy risk premium in the pre-construction stage faced by wind energy project developers in Switzerland.

Keywords: renewable energy; social acceptance; risk management; regulation; permitting; administrative barriers

1.1. Introduction

As a response to the Fukushima meltdown, the Swiss government developed the Energy Strategy 2050 (ES2050), which established ambitious energy efficiency and renewable electricity production targets and a ban for new nuclear power plants (SFOE, 2016a). The Energy Strategy 2050 has been integrated into the revised Energy Law (EnG, 2016), which was accepted by 58.2% of the voters in a May 2017 referendum (Federal Chancellery, 2017). The revised Energy Law grants wind energy projects, together with other renewable energy sources, the status of 'national interest', thus leveling the importance of renewable power generation with other national interests, such as landscape protection (EnG, 2016). Another important implication of the successful referendum is that no *new* feed-in-tariff payments ('KEV', in German) will be earmarked for renewable energy after the end of 2022, and the current KEV system is going to be changed towards a system of feed-in remuneration with direct marketing as of January 2018.[1]

ES2050 recommends a target of 11,400 GWh of new renewables (without hydropower) in 2035 (EnG, 2016) and it is expected that wind energy will play an important part in fulfilling this goal. By the end of 2016, there were 75 MW of wind energy capacity installed in the country, producing roughly 128 GWh of electricity, which corresponds to the electricity consumption of 36,600 Swiss households (Suisse Eole, 2017). These numbers suggest that in order to meet the federal production targets, wind power needs to see significant growth in the coming years. Administrative and regulatory issues[2] are one of the major barriers to development of renewable energy projects in Switzerland and internationally (Battaglini et al., 2012; Burkhardt et al., 2015; Dong and Wiser, 2013; Ceña et al., 2010). Leading Swiss governmental and industry stakeholders identified the duration of administrative processes as an area of concern: it takes more than 10 years to obtain the necessary permits to construct a large wind energy project (Guy-Ecabert and Meyer, 2016; Suisse Eole, 2016a). By comparison, the preconstruction lead times are 4.5 years in Europe, with a considerable variation by country (Ceña et al., 2010). The long duration and complexity of the permitting process result in reduced attractiveness of the Swiss market for foreign and domestic investors, who prefer shorter administrative procedures (de Jager and Rathmann, 2008; Lüthi and Wüstenhagen, 2012). This preference is financially sound: administrative costs are 'sunk' and increase the levelized cost of electricity (LCOE), having a direct impact on project profitability.

[1] For the sake of brevity, we use the term 'KEV' in WP1 to refer to Swiss feed-in tariffs, including the new system of feed-in remuneration with direct marketing as of January 2018.
[2] The words 'administrative', 'planning', 'permitting', and 'regulatory' costs are used interchangeably to refer to the costs borne by the project developer before the construction of wind turbines takes place.

There are several types of costs that are connected to permitting procedures. The first type is easily quantifiable – these are *direct* monetary expenses, such as permitting fees or expenses on environmental impact assessment (EIA) and ecological compensation. We argue that administrative delays incur additional *indirect* costs, which have a detrimental and significant effect on financial attractiveness of the wind project due to opportunity cost of capital and foregone profits. Moreover, delays give rise to regulatory and policy risk and uncertainty, with respect to the federal support scheme and possible changes in environmental and spatial planning laws. Taken all together, we posit that direct and indirect costs of permitting and associated risks constitute a significant barrier for wind energy project development in Switzerland.

The aim of WP1 is to quantify the cost of regulatory and policy risks (the 'risk premium') faced by investors in Swiss wind energy projects. The research focuses on the question: **'How can the policy risk premium for planning and permitting of wind energy projects be quantified and reduced?'** To answer this question, we describe wind energy project permitting procedures, summarize empirical data on their costs and duration, evaluate existing regulatory frameworks for wind power development in Swiss cantons, and analyze the impacts that regulatory risks have on LCOE under different scenarios.

The results of this study have significant policy relevance. To invest in renewable energy, project developers have to recover the cost of electricity production (e.g. measured by LCOE) as well as the associated risk premium. While technological and market risks can be reduced through careful due diligence by the project developers, political and regulatory risks are harder to manage (Noothout et al., 2016). Quantifying the risk premium induced by the administrative process will allow a more precise calculation of adequate levels of public support, which will help policymakers balance the multiple objectives of providing investor confidence, securing low-carbon electricity supply, protecting local landscapes and the environment, and maintaining affordable electric rates.

The rest of the WP1 analysis has the following structure. First, we classified the risk categories faced by wind project developers and visualized the complexity of the administrative process for building large wind energy projects. We evaluated cantonal regulatory frameworks for wind energy development in Switzerland. Then, we quantified the policy risk premium based on the calculations of project profitability and LCOE under eight different scenarios. Finally, policy implications and recommendations for risk reduction are derived, informed by the model results and interview insights.

1.2. Risk categories in wind energy investment

This section investigates ten risks from the wind energy projects developer's perspective, adapted from Noothout et al. (2016) (Figure 1). Careful consideration and weighting of wind energy project risks are paramount for successful project completion. This risk framework shows that some risks are regulatory in nature and can be somewhat mitigated, while a number of other factors need to be accepted 'as is', exposing the project developer to cumulative project risk.

Policy design risk, policy change risk and administrative risk are the most relevant for our research, since they are policy-related and cannot be easily managed by the project developer. Policy design risk is connected to opportunities and threats arising from the policy instrument design by the authorities, including duration and size of support and availability of a support cap. Since 2009, Swiss authorities have been offering KEV feed-in-tariff, which is a fixed rate paid for electricity produced from renewable sources for the duration of 20 years (SFOE, 2016b). The KEV ensures that electricity generators receive compensation for the green power they produce and shields the project cash flows from price volatility of the electric power markets. Moreover, wind projects that are ready to be built enjoy preferential treatment in the KEV system, meaning that they are considered for KEV-support despite the long waiting list (in German, Springersystem) (SFOE, 2016a).

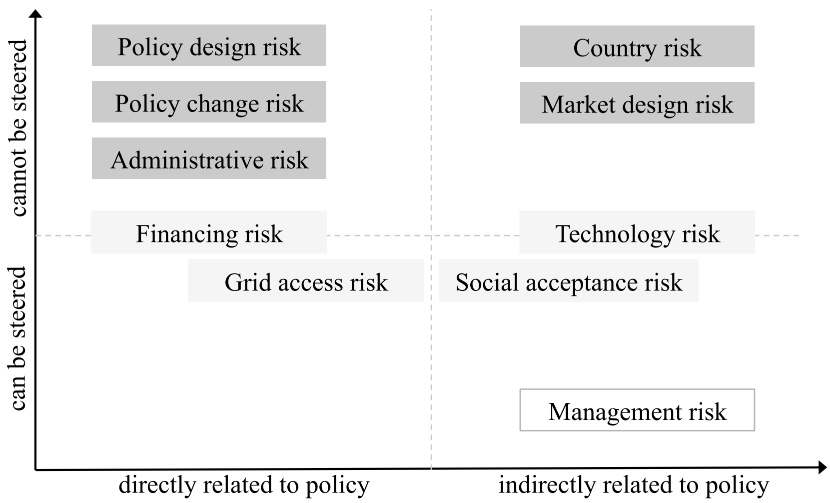


Figure 1. Risk categories in wind energy project development. Own illustration.

Even though KEV offers an attractive and stable revenue stream, there are several challenges with the current implementation of this policy instrument in Switzerland, which translate into considerable risk for developers. The first challenge is the risk of not receiving KEV (considered by Scenarios VI-VIII in section 1.5.1.). There were 361 wind projects with a capacity of 843 MW waiting to be approved for KEV-support in the first quarter of 2017 (Stiftung KEV, 2017). Another 509 planned wind energy projects with a nominal capacity of

1,137 MW have received confirmation of KEV support if and when they are built (ibid). Relieving this bottleneck could contribute significantly to achieving Switzerland's renewable energy goals. Even if only half of the currently planned projects were implemented by 2035, this would lead to an expected annual power generation of 1,748 GWh or 15% of the ES2050 target.[3]

Policy change risk: The second challenge is uncertainty about the subsequent support scheme after the KEV system is discontinued. The revised Energy Law specifies a sunset clause that phases out feed-in tariffs after 2022, suggesting that the majority of wind projects on the waiting list are unlikely to receive KEV support (SFOE, 2016a). The design of a possible public support scheme after 2022 is currently unknown, which is a source of considerable uncertainty for project developers.

Administrative risks can be recognized as a significant hurdle to wind power development in Switzerland, as they have been internationally (Ceña et al., 2010; Lüthi and Prässler, 2011). The risk stems from complex permitting procedures (see figure 3), variations of procedures by canton, changing requirements for environmental impact assessment (EIA), long administrative lead times, multiple opportunities for objections on the cantonal and municipal level, and the high number of authorities involved. The administrative risks bring about additional costs (e.g. new environmental impact studies), cause project delays (e.g. pending court cases), and introduce uncertainty (e.g. project's chances of receiving KEV).

Social acceptance risk: Another important risk in the planning phase is connected to social acceptance. Note that social acceptance is closely intertwined with administrative risks, since projects with significant opposition from the local population or the NGOs are often delayed and are less likely to receive the necessary permits. Generally, Swiss public opinion polls show high approval ratings of wind energy: favorable public opinion has been a defining trend in Switzerland for more than a decade (Geissmann, 2015; Ebers and Wüstenhagen, 2016; Tabi and Wüstenhagen, 2015; Tamedia, 2017). Even though intense political campaigns ahead of voting can lead to opinion swings (Rinscheid and Wüstenhagen, 2016), local voters accepted 12 out of 13 specific wind energy projects in the past four years (Suisse Eole, 2016b).

Public support for wind energy does not mean that all stakeholders are on board with wind energy development. Often, there is a highly organized and influential opposition, which presents a variety of arguments against wind power development. These concerns are usually related to impacts of wind turbines on different aspects of local life: environmental (impacts

[3] Own calculation based on data from Stiftung KEV (2017).

on local flora and fauna, landscape change), emotional (place attachment), technological (contestation of wind technology), health-related (impact of noise, flicker), and economic (unfavorable perceived cost-benefit ratio of wind power development). In the academic literature, the issues of social acceptance are discussed in the context of environmental equity and fairness of renewable energy generation (e.g. see Wolsink, 2007; Wüstenhagen et al., 2007). The project developers usually search collaboration and compromise with the opposition, which might involve commissioning of additional studies, introduction of ecological mitigation measures, changing the location of turbines, reducing the number of turbines, and switching off turbines when birds and bats are most likely to be impacted. Our estimations show that these factors may have significant financial consequences for the project developer. Social acceptance risk can be addressed through a careful stakeholder management strategy, but cannot be fully avoided.

A wind project might receive dozens of objections, most of which are settled out of court. When a compromise cannot be found, the courts are likely to get involved. The task of the court is to weigh the conflicting interests: for example, environmental protection versus domestic energy production (Plüss, 2017). Court cases have considerable impacts on the project's cash flow. Court deliberations lead to direct monetary expenses, such as remuneration for lawyers, expenses for commissioning new studies and project managers' work hours. The objections often lead to considerable delays, putting the project on hold for the duration of the court deliberations. Municipal courts are likely to hear a case in about six months, while the cantonal courts might require a year to reach a decision. A federal court is likely to need several years to announce their verdict. Multiple court cases might delay the project to the extent that it is no longer realizable.

Grid access risk: The project developer greatly depends on the availability of a grid connection, therefore, this is among the first points to be clarified in the initial project stages. If there are no suitable connection options available, the developer usually abandons the project idea, because building new electric infrastructure can be prohibitively expensive. Generally, project developers tend to develop wind projects in their own grid area (if they are an electric utility) or seek a close collaboration with the local grid operators.

Financing risk: Due to the stability of the Swiss financial system and currently very low interest rates, the developers are able to finance wind projects with relatively low cost of capital. Yet, financing wind projects in Switzerland is directly related to the availability of KEV, thus connecting the financing risk of project development with federal policy-making. The interviewees have reported that without the KEV, their projects are unlikely to obtain financing (current market prices for electricity are too low to make investment in wind power profitable). In the absence of KEV, a long-term power purchasing agreement might make the wind project financially attractive, if it covers LCOE.

Technology risk relates to the level of maturity of wind energy technology. Even though wind turbines are a novelty in many regions, wind power is a mature technology. The developer cannot influence the maturity of the best available technology, but a project can be designed to use the most appropriate technological solution, given local wind conditions, altitude, and environmental impacts. In recent years, technological progress enabled building increasingly larger turbines for increasingly lower cost, which tremendously improved cost-efficiency of wind energy per MW of installed capacity. One of the challenges of rapid technological development is that in the case of serious delays, by the time the project obtains all the necessary permits, the technology specified in the permitting documentation may be outdated or even no longer available. In this case, some permitting steps need to be repeated.[4] On the other hand, some project delays can also be an advantage, as they allow the developer to gather further information about the site and employ more efficient wind turbines that become available on the market.

Management risk is related to the overall experience level of the project developer to successfully plan, commission, operate, and decommission or repower the wind project. Our interviews identified a significant learning-by-doing effect, as project developers learn about the complex permitting procedures. An experienced project team has the potential to reduce management risk.

To complete the picture, project developers are subject to the market design and country risks, which equally apply to all electricity producers. These two risks pertain to such factors as: political stability, level of corruption, economic development, design and functioning of the electricity market, the legal system and exchange rate fluctuations. The Swiss electricity market is partially liberalized, with the second stage of liberalization depending on an electricity trading agreement with the EU. The electricity market is dominated by public utilities, which makes the entrance of smaller players more challenging. This stands in contrast with many private wind energy developers who are active in such countries as the US, Germany, the UK, or Sweden (e.g. Bergek et al., 2013). At the same time, Switzerland is a rather small market, which makes large-scale renewable energy developments challenging. As a result, many Swiss developers have built or acquired wind projects abroad (see discussion in WP2).

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[4] One standard practice is to use approximate turbine characteristics in the beginning of the permitting process and avoid specifying the turbine model for as long as possible.

1.3. Wind energy project development process

Wind energy projects are subject to a rigorous technical, financial, ecological, and geological evaluation, with the involvement of multiple stakeholders (Twele et al., 2016). Figure 2 shows the project development path of a wind park, consisting of six distinct steps: feasibility study, pre-project, main project, construction, operation, and repowering or decommissioning.

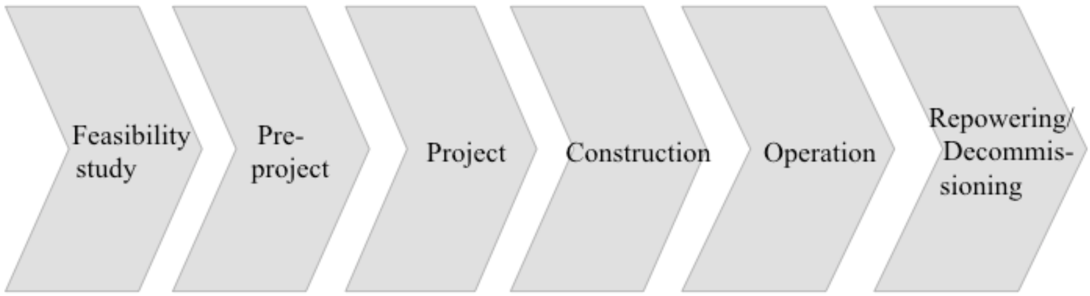


Figure 2. Wind power project development path

In Switzerland, the pre-construction stage (first 3 project steps) can last from 6-7 years without objections and stretch up 15 or more years in case the project faces regulatory hurdles or opposition. In this stage, the project developer expects to spend 5-10% of total budget on planning and permitting activities, which might range from several hundred thousand Swiss francs (in case no EIA is needed) to 3-6 Mio CHF. It must be noted that exact development costs are difficult to predict, since the requirements for realization of wind projects have increased tremendously, putting an upward pressure on pre-construction budgets. Moreover, pre-construction costs do not linearly increase with project size, as they are made up from the fixed costs (independent of project size) and variable costs (dependent on project size, but also on location, situation in the community, objections, cantonal planning decisions, etc.). Thus, larger projects tend to expose project developers to higher pre-construction risks (and expenses), because they require more extensive EIAs, more permits for measuring towers, complex technical planning, and coordination among multiple jurisdictions and landowners. On the other hand, in case of larger projects, the development costs are split among the larger installed capacity, thus reducing cost in per MW terms. To mitigate pre-construction risks, project developers were observed to form partnerships for development of larger projects (cost-sharing) or develop a small lighthouse project first (cost-minimizing). In both cases, potential project failure would result in smaller monetary losses.

Exact pre-construction steps somewhat vary by the developer, their prior experience, and the jurisdiction. The initial 'exploratory' stage of the project results in the feasibility study, which usually takes 1-2 years to complete. The study includes rough wind potential evaluations, initial consideration of environmental impacts, accessibility options, preliminary geological assessment of the grounds, evaluation of suitable wind turbines, and initial financial appraisal. In this phase, the approximate project location and the number of turbines are proposed. This is also the time for the initial contact with local stakeholders. The authorities are contacted for information on permits and zoning requirements. Consent of the land owner(s) is of paramount importance, and it is usually secured through a contract. Interconnection options are discussed with the grid operator. Most project developers apply for KEV by submitting a free-of-charge online application to the national grid operator, Swissgrid. This is a rather fast and straightforward procedure. If the KEV-approval is granted, the project developer has to notify the authorities of the project status every two years.

At the pre-project stage, all of the previously mentioned points get a deeper and more detailed assessment. The project developer obtains reliable wind speed data, by building a wind measurement tower to monitor wind speeds for at least a year. A more detailed pre-project file is submitted for evaluation to the municipality and the canton, so that the project can be integrated in the zoning plans.

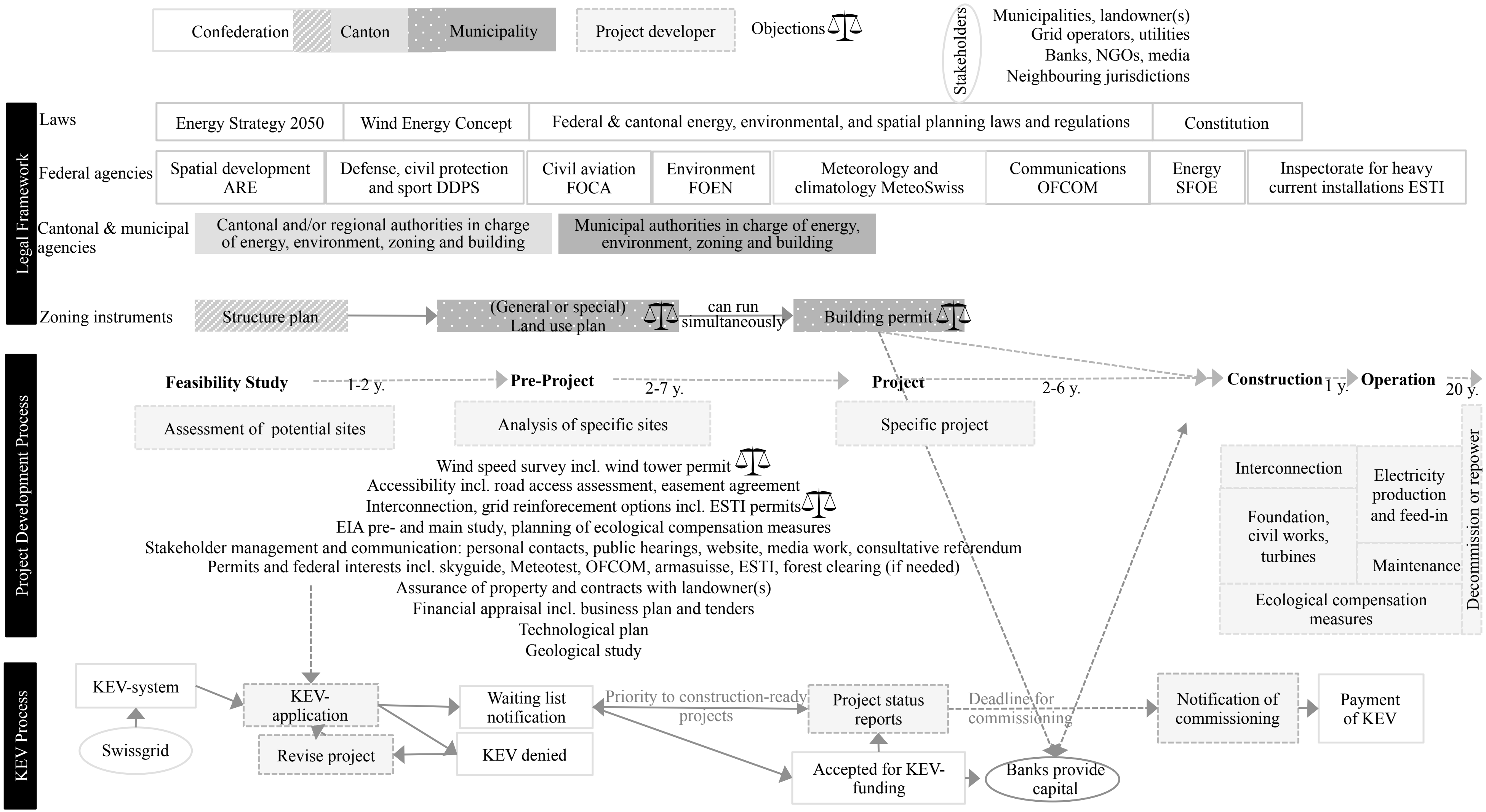
The main project builds upon the outcome of the pre-project and includes a number of detailed studies, which are made to satisfy the building permit application and ESTI permit requirements. This stage can take several years, but usually stretches out longer due to delays. The main project file usually includes the following components: a detailed wind speed evaluation, road access assessment, an interconnection study, contracts with the landowner, a technical plan, a business plan, and a full EIA with suggested measures of ecological compensation. The EIA, compulsory for projects over 5 MW, is an especially important part of the project plan, as it assesses the project's influence on flora, fauna, landscape, and noise exposure (Federal Council, 2016). The EIA often represents a stumbling stone for project developers. Authorities, courts and external stakeholders can require additional environmental studies, which range in cost between 30 and 300 kCHF each and take months (and sometimes several years) to complete. It has been announced that the EIA requirements will be specified in a chapter on wind energy of the EIA handbook, but this chapter has not been issued yet. Generally, the authorities recommend concentrating wind power developments in the areas with high wind potential that are already developed, thus avoiding locations with high natural value (SFOE, 2016c).

Finally, the municipality decides whether to grant the project a building permit, which takes several years with a possibility of a referendum. After the project receives all necessary permits, the construction phase begins. In order to install wind turbines, a number of infrastructural improvements (clearing forests, building roads) are often needed. The next phase is the operational phase, which is the longest phase of the project cycle. It can last 20 years or more, and it is the time when the project is generating revenues. During this time, the project developer might also implement ecological compensation measures to mitigate project impacts on flora, fauna and local residents. After the end of the operational phase, the project can be either decommissioned or replaced by new turbines (repowering; Deloitte, 2015).

While the six steps of the project development process look quite straightforward in figure 2, the picture becomes more complicated when the complexities of administrative process are taken into account. In figure 3, we mapped out the permitting steps and the stakeholders involved, with arrows denoting the most significant interdependencies. The information about the administrative process has been obtained through a review of publicly available documents and interviews with federal and cantonal authorities. The aim of the interviews was to cross-check information obtained from public documents and identify the most important bottlenecks. Industry-related data were gathered through 22 confidential interviews with wind energy project developers in German and French-speaking parts of Switzerland.

As evident from this visualization, the project developer has to obtain permits or decisions from a number of federal agencies, including aviation authorities, military authorities, the Federal Inspectorate for Heavy Current Installations, Federal Office for the Environment, to name a few. To simplify this permitting process, the Federal Office of Energy is currently setting up a one-stop-shop, called 'guichet unique' (SFOE, 2016c). This shall allow project developers to have a single point of contact with relevant federal authorities, instead of having to coordinate among multiple agencies. Even though federal authorities play an important role in the permitting process, the permitting authority lies with the cantonal and municipal agencies responsible for energy, zoning, the environment, and building (SFOE, 2016c).

Figure 3. Planning and permitting of wind energy projects in Switzerland



1.4. Cantonal regulatory framework for wind energy development

Based on six criteria, the authors identified three groups of cantons (cf. Table 1), depending on the level of support that cantonal regulatory frameworks have had for wind energy as of November 2016. The criteria included, whether: 1) a cantonal wind energy perimeter planning approach has been selected (yes or no), including information on the type of approach (positive, negative or hybrid wind perimeters), 2) a cantonal wind resource map has been completed (yes, under construction, or no), 3) cantonal wind energy goals have been defined (yes or no), 4) wind energy potential has been identified (yes or no), 5) wind energy is incorporated into the structure plan (yes, under evaluation, or no), 6) potential wind sites or exclusion zones have been identified (yes, under evaluation, or no). From the interviews, it became apparent that criteria 5 and 6 were relatively more important for the project developers. Hence, we assigned more importance to these two criteria when dividing cantons into groups. The inputs to evaluate the regulatory framework were obtained from Dällenbach (2016), who documented publicly available information in support of this project. This information has been internally discussed and validated.

Even though only six cantons currently have large wind installations, most cantons have already integrated wind energy into their structure plans. A structure plan, the main zoning instrument of the canton, can take several years to complete, and, depending on cantonal law, needs to be approved by the Federal Council and the cantonal government or parliament. The cantons have significant differences in their planning approaches. Most cantons have defined positive wind perimeters (in German, Positivplanung), outlining locations (in German, Interessensgebiete) where wind turbines can be installed, while some cantons adopted negative planning (in German, Negativplanung) and have specified exclusion zones (in German, Ausschlussgebiete), where wind power cannot be developed. Several cantons adopted a hybrid approach, deferring most zoning tasks to regional authorities (in German, Regionalplanung) (e.g. BE, LU, VD, GR) or employing a matrix to support decision-making (SG). Once the project (or a site) is in the structural plan, a land use plan has to be developed and subsequently accepted by the municipality and, in some cases, by the canton.

Moreover, the majority of cantons have acknowledged existence of wind potential in their territory and half of them have defined a specific wind energy production goal. A significant share of the cantons articulated a preference for concentration of wind installations in larger projects, recommending to build a wind park (SG, SH, BL, SO) in general, or specifying minimum number of turbines – either more than three (AG, AR, GR, LU) or five (JU) – or recommending a wind park with annual power generation of more than 10 GWh (FR, NE, VD, VS). From an economic point of view, this recommendation is understandable, as it allows spreading the permitting costs over a larger project volume. On the other hand, the inherent push towards larger projects may impede the realization of viable smaller community projects that tend to be positively correlated with local acceptance (Tabi and Wüstenhagen, 2015).

Based on the regulatory scores, there were seven cantons in Switzerland with the most advanced regulatory framework to support wind energy. These cantons have selected a cantonal planning approach, and in their majority have completed a wind resource map, recognizing a positive wind potential in their territory and establishing wind energy production targets. Most importantly, these cantons have incorporated potential wind sites into their structure plans.

The cantons in the second group have achieved a number of milestones with respect to integrating wind energy development in their regulatory framework and may achieve the 'advanced' status if remaining issues are clarified. For example, the cantons of Vaud (1st group) and Valais (2nd group) established the most ambitious wind energy production goals, aiming to generate 500-1,000 GWh/a or 750 GWh/a by 2035 respectively. The cantons in the third group have emerging regulatory frameworks. Even though some of them have already identified a positive wind potential in their territory, specific sites are still to be integrated into the cantonal zoning plans and wind energy production goals are to be identified.

While the intent is to provide a snapshot of existing regulatory frameworks, certain caution is merited when interpreting the results of this grouping. First, cantonal regulatory frameworks are constantly being updated. Second, differences in planning approaches sometimes made it difficult to assign the canton into a specific category, thus limiting the validity of direct comparisons among cantons. Finally, the table omits a number of 'soft factors' such as authorities' openness towards wind energy, existing knowledge about wind power (current installed capacity is a possible indication) or the future wind energy potential (KEV applications might be a better indicator). Rather, the table illustrates whether the cantons have provided important regulatory guidelines in their planning, which are helpful for wind energy development.

Table 1. Cantonal regulatory frameworks for wind energy development as of November 2016

Canton	Cantonal planning approach selected	Type of planning approach	Cantonal wind resource map	Cantonal WE goals defined	Cantonal WE production goal	Positive WE potential identified	WE included in structure plan	Potential wind sites or exclusion zones defined
AG	yes	+	yes	yes	50 GWh/a by 2035	yes	yes	yes
AI	yes	+	yes	no	N/A	yes	yes	yes
BL	yes	+	no	yes	20-30 GWh/a by 2030	yes	yes	yes
GR	yes	hybrid (regional/-)	under construction	yes	200 GWh/a	yes	under evaluation	yes
JU	yes	+	yes	yes	80 GWh/a by 2021, 150 GWh/a by 2035	yes	yes	yes
SH	yes	+	yes	no	N/A	yes	yes	yes
VD	yes	hybrid (+/excl. zones)	no	yes	500-1,000 GWh/a	yes	yes	yes
AR	yes	+	yes	no	N/A	yes	under evaluation	under evaluation
BE	yes	hybrid (regional)	yes	no	N/A	no	yes	yes
FR	yes	+	no	no	N/A	yes	yes	yes
GL	yes	+	no	no	N/A	yes	yes	yes
LU	yes	hybrid (regional/+)	no	no	N/A	yes	yes	no
NE	yes	+	no	yes	200 GWh/a by 2035	no	yes	yes
SG	yes	hybrid (matrix evaluation)	no	no	N/A	yes	yes	yes
SO	yes	+	no	no	N/A	yes	yes	yes
TI	yes	+	no	yes	ca. 28 GWh/a	yes	yes	yes
TG	yes	+	yes	no	N/A	yes	under evaluation	under evaluation
UR	yes	+	no	no	N/A	no	yes	yes
VS	yes	+	no	yes	750 GWh/a by 2035	yes	under evaluation	under evaluation
BS	no	N/A	no	no	N/A	no	no	no
GE	no	N/A	no	no	N/A	no	no	no
NW	no	N/A	no	no	N/A	yes	no	no
OW	no	N/A	no	no	N/A	yes	no	no
SZ	no	N/A	under construction	no	N/A	yes	no	no
ZH	no	N/A	yes	yes	20 GWh/a by 2050	yes	no	no
ZG	no	N/A	no	no	N/A	no	no	no

1.5. Quantification of the policy risk premium

1.5.1 Methods of policy risk premium quantification

The following section focuses on quantification of the risk premium, which was done by comparing the profitability and the LCOE of the reference project (risk-free scenario) with several risk-adjusted scenarios, when the project witnessed regulatory challenges. The calculations were based on the discounted cash flow model, expressing project profitability in terms of the Net Present Value (NPV) and Internal Rate of Return (IRR), which are standard project evaluation methods in finance (Brealey et al., 2012). For calculation of project cash flows, the authors use annual Free Cash Flow to Firm (FCFF) values.

The LCOE calculations were based on an established method of accounting for project expenses and predicted electricity production at certain periods of time. LCOE was calculated with the following formula (adapted from Kost et al., 2013):

$$LCOE = \frac{\sum_{t=0}^{n} \frac{A_t}{(1+WACC)^t}}{\sum_{t=0}^{n} \frac{M_{t,el}}{(1+WACC)^t}}.$$

LCOE is levelized cost of electricity in Rp./kWh;

A_t are all project expenses in Rp. (0.01 CHF) in year *t*, including permitting expenses in the pre-construction stage, construction expenses, ecological compensation, and O&M expenses once the project is built;

M_t is produced electricity in kWh in year *t*;

WACC is the discount factor;

n is the project lifetime, including pre-construction stage. It should be noted that our calculations of LCOE do not take into account taxes, so caution is advised in comparing LCOE results with the level of feed-in tariffs.

The reference case assumptions were selected to describe a financially attractive wind energy project with realistic features, which have been cross-checked with project developers during the interviews (Table 2). The reference case presents a planned wind park consisting of 9 wind turbines, with a capacity of 3 MW each (27 MW in total). The capacity factor, which is a measure of annual electricity generation per MW installed, is 20.9%, based on the average production values of wind energy projects in Switzerland in 2015 (Wind Data, 2017). The turbines' efficiency decreases at a rate of 1.6% per year (Staffel and Green, 2014). The project developer expects the planning to take 7 years, construction to be completed in 1 year, and the turbines to generate electricity for 20 years. The project developer discounts her annual cash flows at the weighted average cost of capital (WACC) of 3.97% (SFOE, 2016d). Inflation rate is set at zero for simplicity. The capital expenditure is fully depreciated in 20 years. Corporate tax rate is 17.81%, which is an average corporate Swiss tax rate (KPMG, 2016). The model assumes 1-year intervals for cash flows, which occur at the end of each year. There are no assumptions about debt or equity, because the model evaluates incremental cash flows.

Construction cost of the reference project is 59.4 Mio CHF (2.2 Mio CHF/MW) and it costs 660 kCHF to connect the project to the power grid. After the construction, there is an annual expense of 594k CHF (1% of construction costs) for operations and maintenance (O&M), which increases at a rate of 1% per year. The project developer expects to receive a feed-in tariff of 21.5 Rp/kWh for the first 5 years of operation, followed by a lower KEV rate of 13.5 Rp/kWh for the remaining 15 years (SFOE, 2016b).[5] During the interviews, the project developers reported production costs ranging from 10 to 20.5 Rp./kWh.

Table 2. Reference case assumptions

Input Parameters	Value
Technical parameters	
Number of turbines	9
Nameplate capacity per turbine (MW)	3
Capacity factor (%)	20.9%
Decrease in turbine power output (%/year)	1.6%
Planning stage (years)	7
Construction stage (years)	1
Operating stage (years)	20
Financial parameters	
WACC	3.97%
Depreciation, years	20
Corporate tax rate (%)	17.81%
Inflation rate (%)	0%
Building and O&M	
Construction cost (CHF/MW)	2,200,000
Interconnection cost (CHF)	660,000
Operations & maintenance (CHF/year)	594,000
Increase of O&M cost (%/year)	1%
Ecological compensation measures (CHF)	1,500,000
Planning expenses (CHF/MW)	130,000
Revenues	
KEV remuneration in years 1-5, Rp./kWh	21.5
KEV remuneration in years 6-20, Rp./kWh	13.5

[5] For reasons of simplicity, we assumed the standard feed-in tariffs for wind energy in years 6 to 20 rather than the exceptions specified in Appendix 1.3, section 3.2, of the Energy Ordinance (Federal Council, 2017).

Ecological compensation measures are carried out in the year of construction only if the project is realized, and can be interpreted as NPV of all expenses on ecological compensation over the project's lifetime. They are assumed to cost 1.5 Mio CHF, which is based on high number of planned turbines and increasingly stringent ecological requirements. After 20 years of power production, the developer expects to sell the turbines to the second-hand market, which should cover decommissioning costs, so the decommissioning is assumed to be cost-neutral. Note that project expenses in the reference case are rather conservative, tending to underestimate the project's risks rather than overestimate them.

In the beginning of the project, the developer earmarks a planning budget, of 130,000 CHF per MW of planned capacity (3.5 Million CHF), corresponding to ca. 6 % of construction cost. For the reference case, project planning and ecological compensation expenses were informed by the values summarized from the interviews (Table 3). This represents a rather conservative assumption, given that international literature reports planning budgets reaching 10% of the construction cost (Krohn et al., 2010; Blanco, 2009). The planning expenses include wind measurements, environmental studies and mitigation measures, salaries for lawyers, engineers, financial managers, as well as PR and stakeholder management expenses. The minimum and maximum values vary considerably depending on the interviewer, which can be explained by differences in project accounting, varying project complexity, and project experiences. Still, Table 3 presents a useful illustration for project planning expenses.

One of the most significant cost categories are connected to EIA and ecological mitigation measures, often accounting for half of the planning budget. EIAs take 1.5 to 6 years to perform and range in total cost from 100k CHF for simpler studies to 700k for longer and more complex estimations. Similarly, all except for one interview reported ecological compensation measures in excess of half a million CHF. Coordination with stakeholders was a significant cost category for some project developers, leading to spending of up to 1.1 Mio CHF over the project lifetime. In contrast, other developers planned several hundred thousand CHF on such activities per year during the planning stage, depending on the type of activities carried out (organization of site visits and informational meetings with or without catering and noise simulations; preparation of dossiers, website, posters, and flyers; communication campaigns; support of local life).

The technical dimension of the project requires planning by experienced engineers, which can be done in house or outsourced to an engineering bureau, costing on average about 400k CHF (might include geotechnical study, road access survey etc.) and taking 4-5 months to complete. Similarly, wind measurements depend on project complexity and can be completed in several stages, costing from under a 100k to more than half Mio CHF. Obtaining the permit for wind measurements can take several months for approval and is subject to objections. Planning for interconnection might relief project developer of about 100k.

One of the cost categories that are most difficult to predict is the HR expense for project management and expenses for legal advice, as these directly increase with project delays, number of objections, number of subsequent court cases and court instances involved. We made conservative estimation of 500k over the planning period, but also provide mean values for legal expenses per court case, which would be added to the planning budget as they arise. Finally, we include the cost of insurances, land rent and leases, estimated at 50k.

Table 3. Estimation of average expenses of wind project planning

Project planning expenses (CHF)	Mean	Min	Max	St. dev
Ecological compensation measures	844k	100k	1,700k	536k
EIA pre-study and main studies	417k	100k	700k	164k
Coordination with stakeholders and PR	550k	200k	1,100k	288k
General technical planning	398k	100k	1,500k	480k
Wind speed measurements	243k	80k	530k	152k
Planning of grid interconnection	109k	50k	200k	58k
Federal permits and interests	20.5k	9k	35k	7.7k
HR expenses, accounting, controlling, legal advice	500k			
Municipal court cases (1/2 year delay)	30-50k/case			
Cantonal court cases (1 year delay)	30-50k/case			
Federal court case (2 years delay)	50-100k/case			
Insurances, land rent, leases	50k			

In order to evaluate marginal impacts of different administrative hurdles, we compute the NPV, IRR and the LCOE in the reference case and different scenarios. Each scenario investigates two levels of risks: low risk and high risk. The overall aim of scenarios is to determine which factors have the highest impact on project profitability and hence represent the highest policy risk.

Scenario I investigates changes in profitability and LCOE as a result of a 3-year (low risk) and 10-year (high risk) delay in project development in the pre-construction stage. Planning budget increases by 100k CHF for every year of delay, which accounts for additional project management hours, legal advice costs and coordination efforts.

Scenario II illustrates the detrimental effect of policy-induced reductions in capacity factor. Full load hours are usually predicted based on wind measurements in the pre-construction stage. Yet, decreased hours of operation can be a measure of ecological compensation, and the turbines might be switched off to protect migratory birds or vulnerable bat species. The turbines in the reference case operate with 1831 full load hours a year (20.9% capacity factor), while Scenario II evaluates the changes in LCOE if the turbines work with a capacity factor of 19.9% (low risk) and 17.9% (high risk). A similar negative effect is expected in Scenario III, where there are fewer turbines (5 low risk or 7 high risk) permitted than originally planned. In Scenario IV, we investigate cost overruns that increase the planning budgets to 200k CHF (low risk) and 400k CHF (high risk) per MW of installed capacity.

Table 4. Summary of scenarios

Scenario	Description	Details
I	Delays	3 or 10 years delay in permitting
II	Lower capacity factor	Reduction of capacity factor to 19.9% or 17.9% due to switching off of turbines
III	Lower installed capacity	7 or 5 turbines are permitted instead of 9
IV	Planning costs increase	Increase of planning costs to 200k CHF/MW or 400 k CHF/MW
V	Combination scenario	Low risk: 3 years of delay, capacity factor is 19.9%, 7 turbines permitted, planning budget is 200k CHF/MW High risk: 10 years delays in permitting, capacity factor is 17.9%, 5 turbines permitted, planning budget is 400k CHF/MW
VI	KEV phased out	Electricity sold at market price of 4 Rp./kWh or 8 Rp./kWh
VII	KEV payments delayed	Payments delayed by 1 or 2 years, electricity sold at market price of 4 Rp./kWh
VIII	KEV payments reduced	KEV reduced by 10% or 20% all years

Scenario V combines multiple administrative hurdles and is, in many ways, mirroring the reality of several Swiss wind projects. First, low project risks from Scenarios I-IV are combined: planning takes 10 years, the planning expenses increase to 200,000 CHF/MW, only 7 out of 9 turbines are permitted, and the capacity factor is reduced to 19.9%. In the high-risk combination scenario, we investigate a 5-turbine project with the pre-construction stage of 17 years and planning budget of 400k CHF/MW, with capacity factor of 17.9%.

Finally, we investigate the impacts of the level and duration of KEV payments on project's profitability (represented by IRR and NPV). Since LCOE does not account for project revenues, it is not calculated here. We investigated whether wind energy projects will be developed in Switzerland without KEV (Scenario VI) and what levels of electricity market prices are necessary to make wind projects financially attractive. For modeling simplicity, we disregarded electricity price volatility and assumed a constant price of 4.0 Rp./kWh, which equals the average spot price for Swiss base load electricity in the day-head market between July 2015 and July 2016 (Bloomberg, 2016) and which is also within the range of BFE's electricity price projections (SFOE, 2016d). The low risk Scenario VI assumes the market price to 8 Rp./kWh[6]. Additionally, we looked at project profitability if KEV payments are delayed by 1 or 2 years and the electricity is sold at the market price of 4 Rp./kWh (Scenario VII). Final-

[6] This is an optimistic electricity price level assumption in light of currently low electricity prices. Yet, given the wind project's lifetime of several decades and potential future price changes, it is worth considering. Moreover, this assumption is representative of the electricity price level when KEV was initially introduced.

ly, we calculated profitability changes due to an overall reduction in KEV support (by 10% or 20%) (Scenario VIII).

1.5.2 Results of policy risk premium quantification

This section provides an indication of the size of the policy risk premium faced by project developers due to challenges in the pre-construction stage. We compare LCOE of the risk-free scenario to the eight scenarios with policy risks introduced in the previous section. LCOE of the reference case is 12.57 Rp./kWh. Financially, the project is a reasonably attractive investment with an IRR of 6.68%, NPV of 10.3 Mio CHF and a payback time of 10 years after construction. The following scenarios illustrate marginal impacts of policy risks on the reference case.

Scenario I: A 3-year delay increases LCOE by 0.16 Rp./kWh and results in 1.76 Mio in losses in NPV (Figure 4). A 10-year delay in project development creates 4.42 Mio in losses in NPV for the investor, increasing LCOE by 0.37 Rp./kWh. Note that these numbers account for only 100k CHF in additional expenses per year of delay, thus increasing the planning budget by 300k CHF and 1 Mio CHF altogether. Despite these insignificant changes in the planning budget (0.5% and 1.7% of construction cost), the estimated profitability losses and LCOE increases are considerable. This observation illustrates an important lesson learned: project delays have much larger impact on project profitability than is obvious from the 'direct' additional expenses.

In addition to 'direct' costs, delays in project development are connected to the 'indirect' (hidden) costs, such as the opportunity cost of capital. During the years of permitting, the capital earmarked for the project is not productive, yet, it could have been invested at a profit elsewhere. A simple calculation of the opportunity cost shows that if the project developer in the reference case invested their planning budget of 3.5 Mio CHF into a financial vehicle with an annual yield of 3%, they would have obtained 105k CHF in revenue per year. In 15 years, the project developer would have earned nearly 2 Mio CHF on their initial investment. In case of a wind project, the developer does not see any return on their investment for the duration of the permitting stage. Thus, the idling capital should be of the same level of concern as idling wind turbines.

Moreover, administrative delays make the project developer forego profits from electricity production, which also could have been reinvested. Depending on the assumptions, foregone profits from electricity generation also run into hundreds of thousands of francs, the funds that cannot be reinvested if the project gets delayed. Even though opportunity cost of capital and foregone profits do not enter the financial accounting of the project developer, they should not be neglected, since they reduce overall attractiveness of the project.

Scenario II: Major profit-reducing events can occur if not all planned turbines are permitted or the turbines remain idle due to restrictions. Switching off of wind turbines can be a measure of environmental conservation. The reduction in capacity factor by one percentage point to 19.9%, brings about an average loss in NPV of 2.8 Mio CHF and increases LCOE by 0.63 Rp./kWh. If the capacity factor decreases to 17.9%, the NPV losses amount to 8.4 Mio CHF compared to the reference case. If this high risk is present, the LCOE increases by 2.11 Rp./kWh.

Scenario III: A significant decrease in profitability is experienced if multiple turbines are not permitted. If only 7 of the 9 originally planned turbines can be built, LCOE increases by 0.73 Rp./kWh. If only 5 turbines are permitted, LCOE climbs by 2.04 Rp./kWh. Thus, reducing the capacity factor to 17.9% due to the switching off of turbines has roughly the same impact on LCOE as having 4 of the planned 9 turbines not permitted. The reference project needs at least 14 MW of production capacity to break even. If the project faces additional costs and delays, it requires larger capacities to counterbalance the permitting expenses. This illustrates the sensitivity of wind projects to the number of hours the rotor is allowed to turn and the number of turbines in the park.

Scenario IV: The planning budget is likely to increase when the project is experiencing delays. If the planning costs increase to 200k per MW of installed capacity, not only the project developer will have to invest 1.89 Mio CHF more into the project in the pre-construction stage, the LCOE increases by 0.38 Rp./kWh. In a high risk case, the planning costs would reach 400k CHF/MW, which would increase LCOE by 1.44 Rp./kWh, making the project only marginally attractive with an IRR of 4.88% (Figure 5). From the interviews we have learned that some project developers would abandon a project if the planning cost reaches half a million per MW. The planning costs for abandoned projects need to be implicitly won back by successful projects, putting an upward pressure on the required level of KEV payments.

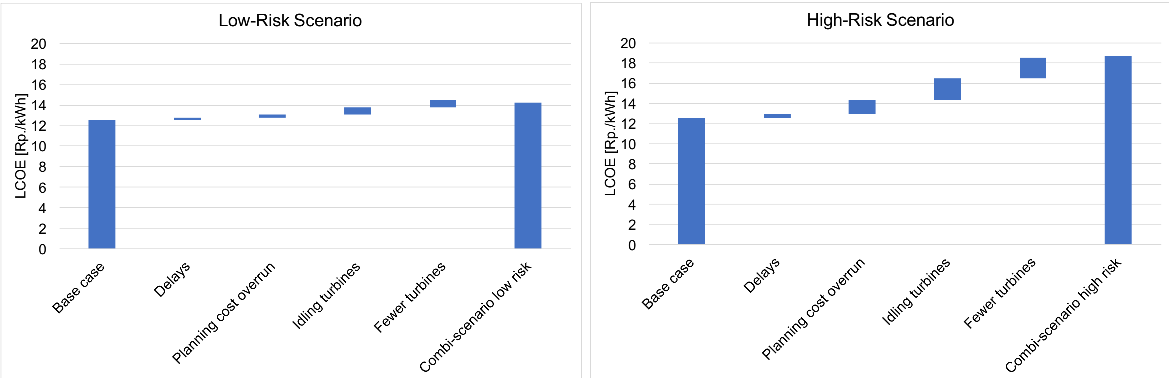
Scenario V: So far the calculations estimated the marginal impacts of policy risks on project profitability and LCOE levels. The low risk combination scenario illustrates a case that is fairly representative of many Swiss wind projects: 3 years of delays, lower than planned capacity factor of 19.9%, 7 turbines permitted, planning budget amounting to 200k CHF/MW. The IRR of the combination scenario is 4.87%, which is still higher than WACC, but does not represent a high-yield investment. At the same time, LCOE would rise to 14.22

Rp./kWh, which is higher than the nominal KEV remuneration in years 6-20. This implies that the profitability of the project would be substantially lower than initially projected.

If we combine the high risk scenarios (10 years delay, reduction in capacity factor to 17.9%, 5 turbines permitted, increase of planning costs to 400k CHF/MW), LCOE rises to the unsustainable level of 18.67 Rp./kWh. The cumulative policy risks would reduce the IRR below WACC, yielding a negative NPV, which suggests that an economically rational developer would abandon the project, as it will not be profitable. The combination scenario illustrates that multiple policy risks are present in reality and have a significant negative impact on a project's financial performance. Unless minimized, these policy risks can hamper the prospects of development of wind energy projects even in the presence of KEV.

Figure 4 presents the effects of the policy risks illustrated in Scenarios I-V on risk-adjusted LCOE of wind energy in Switzerland. In order to make a positive investment decision, a project developer would compare the LCOE with achievable revenues, i.e. remuneration from KEV or electricity sales.

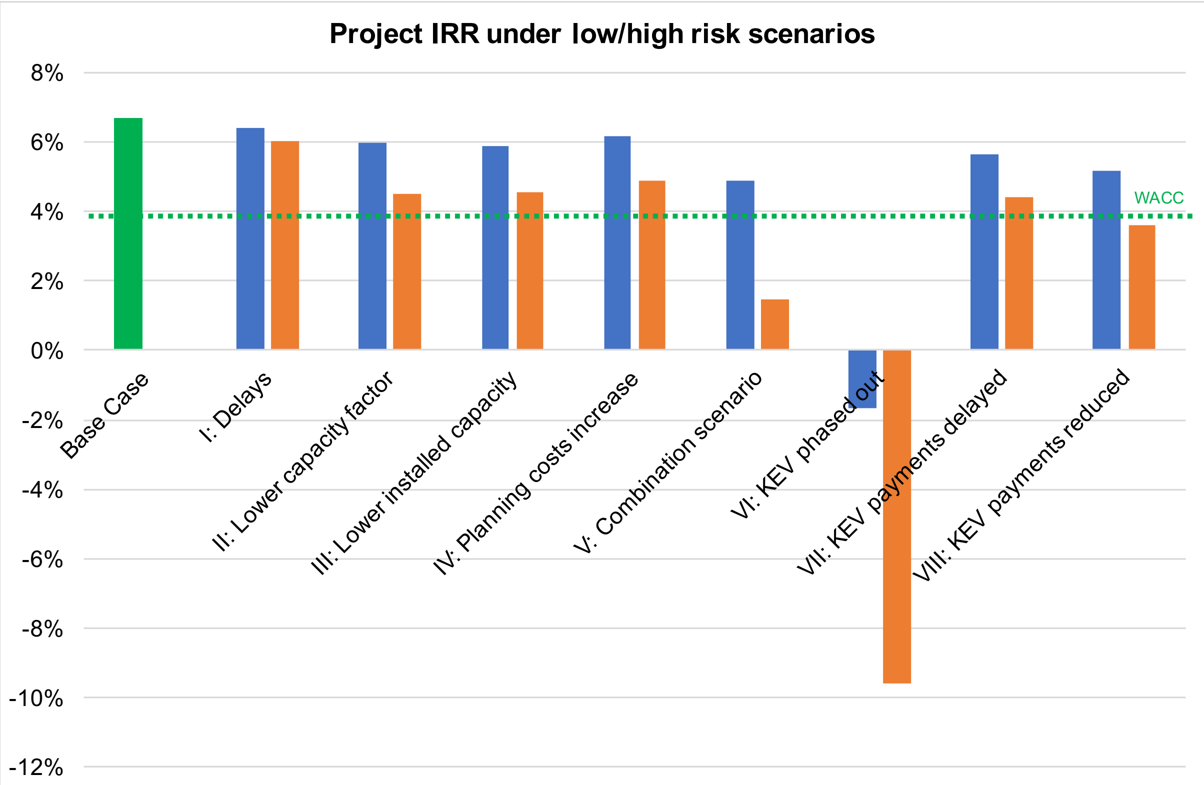
Figure 4. Risk-free versus risk-adjusted LCOE in Scenarios I-V (high vs. low risk)



Scenarios VI-VIII: The highest risks to a project's financial viability are related to the unavailability, reduction, or delays of KEV payments. In line with the information received during the interviews, we find that no wind project can be developed without KEV in the current market conditions. If KEV payments are not available for one year and the electricity price is 40 CHF/MWh, the profitability of the whole project drops by 1.03 percentage points, which would cost the project developer 3.5 Mio CHF. Delaying KEV for 2 years in the initial years of operation is equivalent to not allowing 4 out of 9 wind turbines to be built in NPV terms. A relatively high market price for electricity is required for the project to be financially viable in the absence of a feed-in tariff: with the assumed WACC (3.97%), the wind project's NPV was positive when the average market price of electricity reached 13.5 Rp./kWh for all years of operation. A minimum KEV support of 16.0 Rp./kWh is required for all years of operation to maintain the profitability of 6%. If the size of KEV support is reduced by 10 percent, the project's NPV decreases by more than 5.84 Mio CHF (1.51 percentage point loss in terms of IRR). More significant reductions of KEV, say by 20%, are likely to deter investment, as the net present value of cash flows turns negative and IRR (3.08%) is below WACC. Note that the relationship between the reduction of KEV and losses in profitability is not one to one: if KEV is reduced by 10%, the profitability decreases by more than 22%.

Figure 5 summarizes the discussions in this section, illustrating how the initial project IRR of 6.68% would be affected by the policy risks discussed in Scenarios I to VIII. The dotted green line represents the assumed weighted average cost of capital of 3.97%. Policy risks can significantly reduce the expected rate of return, and let it fall below WACC and even to negative absolute values in some cases, suggesting that the project would turn unprofitable if the assumptions in some of the high risk scenarios materialize.

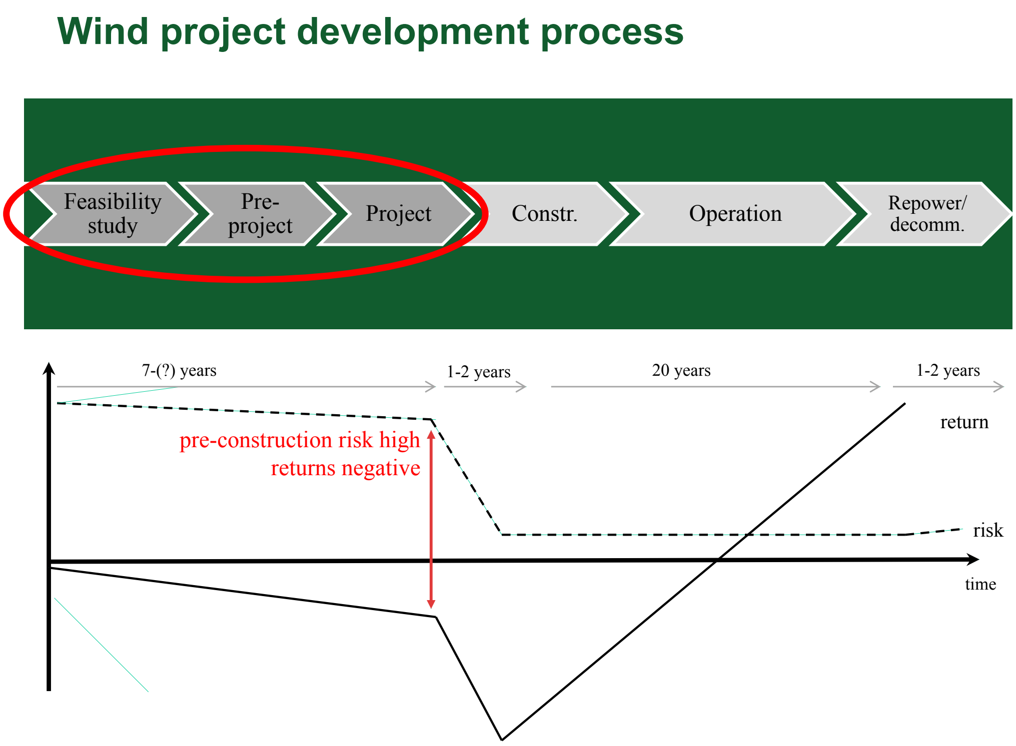
Figure 5. Impact of policy risk on project's internal rate of return (IRR)



1.6. Conclusions of WP1 and policy implications

The profitability of a wind park is determined by an interplay of project risks and returns. Most risks in wind energy development occur in the permitting stage, while returns are only realized after the project is built (see Figure 6). In order to incentivize investment in wind power, policymakers can either 1) reduce the risks in the planning stage 2) compensate investors for taking those risks through higher returns or 3) shorten the planning stage to reduce uncertainty about both risks and returns. Many Swiss wind energy projects currently have a high risk/high return profile. Project developers are facing significant risk in the planning stage, and they receive attractive returns (in the form of the KEV) in those (few) cases where the project can actually be built. From a societal point of view, shifting more projects towards the low risk/low return end of the spectrum would be preferable.

Figure 6. Risk-return profile of a typical wind energy project



Above all, this implies decreasing project risks in the pre-construction stage. Possible measures include simplifying and streamlining permitting procedures, creating regulatory clarity, and expediting court cases. An important consideration is to implement such measures in a way that maintains social acceptance of wind energy by relevant stakeholders. Successful wind projects are characterized by alignment of interest between investors and local communities, which can for example be facilitated by enabling financial participation of the local population in the project (Tabi and Wüstenhagen, 2015). An approach that has had positive effects on social acceptance in some regions of Switzerland was to gain experience with one or a few turbines before planning an extended project. Trying to implement a large wind park in a region without prior experience, in contrast, has proven to be more challenging. A number of other policy measures are possible to improve administrative procedures and reduce the policy risk premium (Table 5).

Table 5. Opportunities for reduction of policy risks

Challenge	Possible solutions
Complex procedures	-Offer checklists to identify acceptable criteria for wind energy projects -Define a federal ‘guiche unique’ in charge of wind energy strategy, planning will remain the jurisdiction of the canton -Allow a simplified permitting procedure if the project is located inside the positive wind perimeter -Allow a simplified permitting procedure if the project is accepted by a municipal referendum -Harmonize the duration of permit validity to a common denominator, which is compatible with the average duration of the planning phase, measuring in years rather than months -Level the playing field of wind energy and other technologies and types of infrastructure (e.g. why does wind energy have to provide bank guarantees about decommissioning) -Harmonize permitting procedure in case the project is located at the intersection of jurisdictions (e.g. encourage coordination of land use plans between communities and cantons)
Long procedures	-Set voluntary deadlines, both for project developers and the authorities. If a deadline is missed, other parties must be notified and a new deadline is to be set -Given high volume of projects to be evaluated, appropriate resources must be offered to the agencies -Clarify how several project steps can run in parallel, e.g. land use planning and building permit application -Coordinate requirements for ESTI procedure and building permit procedure -Reduce iterative nature of project file review, e.g. by specifying the number of rounds to a final decision -Reduce the number of micro-permits e.g. when permits are necessary to cut down a single tree, separate from other permits.
Permitting uncertainty	-Offer venues for exchange of experience between cantons -Offer online project permitting system, which summarizes project status and gives guidance with respect to requirements of different permitting stages -Clarify rules of the EIA requirements and the ecological compensation -Clarify when the wind chapter in the EIA handbook will be available -Clarify construction requirements of projects near ecologically significant zones (buffer zones), sensitive bird and bat habitats -Clarify criteria when wind development is possible in the forested areas and on forest fringes

	-Clarify criteria for acceptable noise levels, which is regulated on the federal level, but has been influenced by court decisions -In addition to positive perimeters, define exclusion zones to increase zoning certainty -Clarify levels of compensation for interconnection -Allow preliminary clarifications (in German, Vorabklärungen) with authorities, if project developers desire
Court cases	-Encourage conflicting parties to settle objections out of court -Establish standing of plaintiffs in a speedy manner -Encourage the objections to be communicated as early as possible, probably already at the structure plan level -Allow pooling of court cases that raise objections on the same topic -Allow pooling of court cases for ESTI and zoning procedures -Allow faster handling if a similar ruling has already been obtained
Planning costs	-Be mindful of the negative effect of downsizing planned wind parks on the cost of electricity generation -Consider a public support scheme to help cover the planning costs, akin to the Scottish 'Community and Renewable Energy Scheme' CARES (Scottish Government, 2013) -Allow prior Swiss and – if applicable – international studies on flora and fauna to be used for EIAs
Social acceptance	-Encourage continuous and early dialogue with stakeholders -Encourage staged development in regions without prior wind energy experience -Develop mechanisms for financial participation of the local population in wind energy projects (citizen investment/community financing) -Encourage partnerships between project developers and local communities -Provide continued political leadership for wind power on federal, cantonal and municipal levels

WP 2: Expected and Realised Risk-Return Profiles of Domestic and Foreign Power Generation Investments

Abstract

The main objectives in WP2 are: (a) exploring which part of past Swiss power generation investment happened domestically versus abroad, (b) comparing expected and realised risks-return profiles of past investments, (c) identifying factors influencing the decision to invest domestically versus abroad.

To address the first objective, we analysed statistics on past energy investments of companies registered in Switzerland through the Bloomberg New Energy Finance (BNEF) database. To address the second objective, we conducted a cross-case study analysis of past investments by Swiss investors in energy projects at home and abroad. To address the third objective, we organised two focus group discussions and conducted 12 interviews with representatives of companies that invested in energy projects in the past 10 years, including an experimental choice task between a project in Germany and a project in Switzerland.

The results show that between 2004-2015, 69% of the new investment in energy projects was allocated abroad and only 31% in Switzerland. The preferred types of energy for new projects were hydropower, wind and gas. While most of the hydropower projects were implemented in Switzerland, the majority of wind and gas projects were implemented abroad. The most popular foreign investment destinations were Germany and Italy.

Expected returns on gas projects were higher than the ones on wind projects; realised returns on wind projects were higher than the ones on gas projects. Expected returns on wind projects abroad were higher than the ones on wind projects in Switzerland, realised returns varied by country and were lower in Germany than in Switzerland. Nevertheless, according to BNEF, 42% of Swiss investors in wind energy chose projects in Germany and only 8% in Switzerland.

The focus group discussions and interviews showed that decision-makers often concentrate on single decision factors, which are important for them, rather than relying on a systematic calculation of future cash flows. Moreover, several of the interviewed decision-makers used arguments about financial profitability when discussing investments in Germany and arguments about social responsibility or political factors when discussing investments in Switzerland.

Keywords: Investment Decisions, Renewable Energy, Wind, Gas, Location Choice, Risk-Return Profile

2.1. Introduction

In 2011, Swiss utilities planned to invest 9.7 billion CHF in renewable energy until 2020, and two thirds of these investments were planned abroad (Windisch et al. 2011). In 2016, Energie Zukunft Schweiz published a study listing a number of Swiss renewable energy projects abroad amounting to about 3205 MW in total (Wanner & Arnold, 2016). According to Windisch et al. (2011), utility companies located in Switzerland explained such a strong focus on foreign investments strategy at the time by limited wind and solar resources in Switzerland, a limited amount of locations appropriate for project development, more secure access to feed-in tariffs abroad, and simpler permitting procedures. In the meantime, utilities from those countries that were potential foreign destinations for Swiss utilities, pursued a similar strategy: German E.On, for instance, has 29% of its renewables' portfolio and only 12% of its wind portfolio in Germany in (E.On Group Annual Report 2015); Italian Enel Green Power has 34% of its renewables' portfolio and only 8% of its wind portfolio in Italy (Enel 2015).[7]

Based on these data, one could assume that utilities see investments in power generation at home as less profitable than investments in energy generation abroad. This makes an interesting case for research, considering that the literature suggests that investment strategies tend to be affected by home bias, a tendency to allocate a larger share of investments at home, and not by foreign country bias, a tendency to favour investments abroad (Ahearne et al., 2004; Huberman, 2001; Tesar & Werner, 1995). Moreover, in the context of the nuclear phase out in Switzerland, the question of domestic power generation capacities becomes more acute and therefore, this study aims to answer the following questions:

a) To which extent did the abovementioned strategies of Swiss utilities become reality? How much investment actually occurred abroad and how much of it happened domestically in the last decade? What were the preferred project types?

b) What were expected and realised returns on these investments?

c) What are the decisive factors affecting the choice of the investment location for future projects?

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[7] https://www.enelgreenpower.com/en/where-we-are.html

2.2. Methods

The research is conducted in three steps to address the research questions specified in the introduction.

The first step is the analysis of realised investments based on the Bloomberg New Energy Finance database. This is done to find out the share of domestic vs. foreign investment, identify the most popular foreign destinations, as well as preferred project types. The second step is a cross-case study analysis of the expected and realised risk-return profiles of 20 gas and wind projects, realised between 2004-2014.

We estimate expected internal rates of return (IRR) under the assumption that the market conditions of the year when the investment decision was taken remain constant. Using the data from the realised years of operation we estimate the realised IRR. We then compare the derived IRRs to hurdle rates, which companies applied to these projects. We derive information about the applied hurdle rates on a case-by-case basis. In some cases, a hurdle rate means a universally applied rate for all power generation projects based on the cost of capital, in other cases hurdle rates are affected by the technology and/or location of the investment.

Comparing expected and realised IRR helps to understand the performance implications of the chosen investment strategy.

IRR (internal rate of return) is the discount rate at which NPV (net present value) equals zero.

$$0 = \sum_{t=0}^{n} \frac{FCF_t}{(1+IRR)_t}$$

n – lifetime, FCF – annual free cash flows.

In this study, the results were calculated with the following input variables: publicly available data on the initial investment amount, estimated lifetime based on the lifetime of similar plants, and estimated annual free cash flows.

Annual free cash flows represent the difference between annual revenues and annual costs.

Annual revenues = Revenue from electricity sales (for gas power plants and wind power plants in Italy) or feed-in tariff (wind power plants in Germany) + Revenue from green certificates (for Italian wind plants) + Revenue from ancillary services (for CCGT power plants in Italy) + Revenue from capacity payment (for CCGT power plants in Italy)

Annual costs = Fixed costs (O&M, personnel, etc.) + Variable costs (fuel price, CO_2 certificates).

The table below outlines the differences in estimations used for the calculation of expected and realised IRR.

Table 6. Input variables for calculation of expected and realised IRR.

Expected IRR	Realised IRR
Electricity price in the year of making the investment	Actual electricity price by year of operation. Projected for the next operation years – equals the electricity price in 2015
Expected production amount declared in the media report at the time of the plant inauguration	Actual production amounts by year of operation. Projected production for subsequent years: average of current performance
CO_2 cost in the year of making the investment	Actual cost of the CO_2. Projected cost – equals the CO_2 cost in 2015.
Fuel price in the year of making the investment	Fuel prices for the years of operation. Projected price equals the price in 2015.

To validate our assumptions about individual parameters and the calculation results, we conducted 5 confidential interviews with company representatives.

Finally, the third research step aims to address the question about factors defining the location choice for future investments. To address this question, we organised a workshop with 2 focus group discussions during the St. Gallen Forum for Management of Renewable Energies on May 27, 2016 and 12 interviews with utilities and institutional investors in March-April 2017, including an experimental choice task between an investment project in Switzerland and abroad.

2.3. Results

2.3.1. Realised investments

According to BNEF data for 2004-2015, Swiss companies allocated only 31% of their investments to domestic power generation.

Table 7. Swiss investments in power generation projects, 2004-2015 (Source: BNEF, 2015)

	In Switzerland		**Abroad**	
	Commissioned projects	*Planned projects*	*Commissioned projects*	*Planned projects*
Renewable power generation (in MW)	930	3036	3393[8]	2611
Fossil fuel power generation (in MW)	55	380	3008	965
	Total in Switzerland (in MW)	4401	Total abroad (in MW)	9976

The most popular foreign destinations were Germany and Italy.

[8] The BNEF data for commissioned RES projects abroad (3393 MW) is roughly in line with estimates by Energie Zukunft Schweiz (2016), who mention 3205 MW.

Our data analysis shows that investments[9] are almost evenly distributed between wind, hydro, and gas projects (see figure 7). Nearly one third of investments were dedicated to non-renewable forms of power generation.

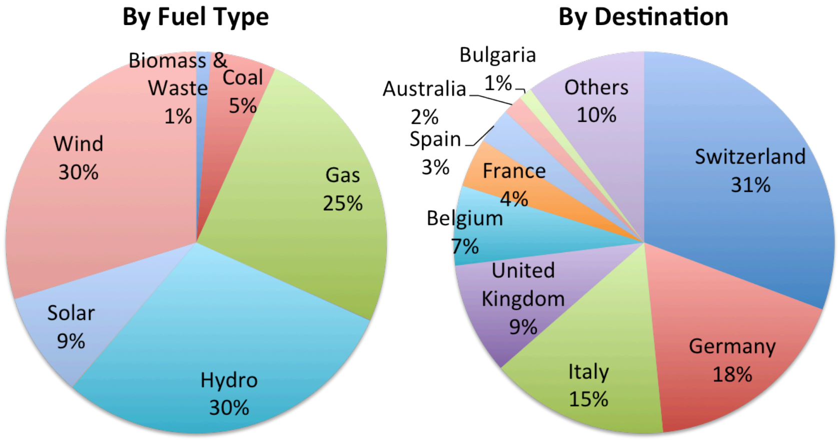


Figure 7. Investment destinations of investors located in Switzerland and projects by fuel type, 2004-2015. Source: Bloomberg New Energy Finance

While most of the hydro projects are conducted within Switzerland, wind and gas projects are mostly done abroad (see figure 8).

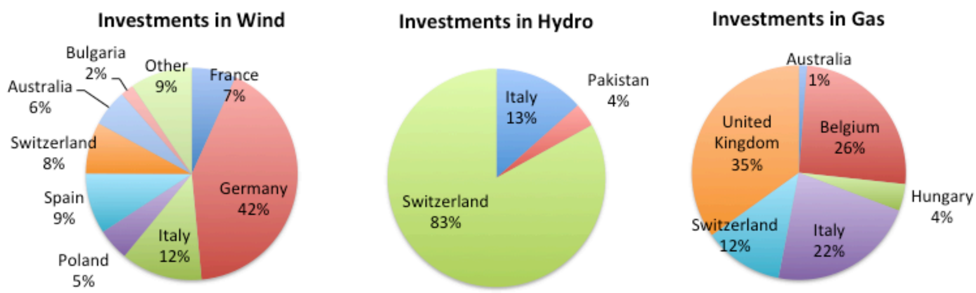


Figure 8. Investment destinations by fuel type, 2004-2015. Source: Bloomberg New Energy Finance

2.3.2. Expected vs. realised risk-return profiles

Based on the analysis of Bloomberg New Energy Finance data, we found that most of Swiss energy-related foreign direct investment went into wind or gas-fired power plants. Therefore, we focused on these project types for further analysis. Taking into account data availability limitations, we were able to analyse the expected and realised returns on 2 gas projects and 18 wind projects. To calculate the expected and realised returns on 2 combined cycle gas turbines (CCGT) and 11 wind projects, we: 1) collected data on lifetime, initial investment, electricity price in the given region before and during the operational time, expected and actual production amounts, operation and management costs, as well as CO_2 and fuel costs where applicable; and 2) calculated expected and realised cash flows. For the remaining 7 wind projects, we collected confidential data about expected and realised returns from interview partners representing wind investors.

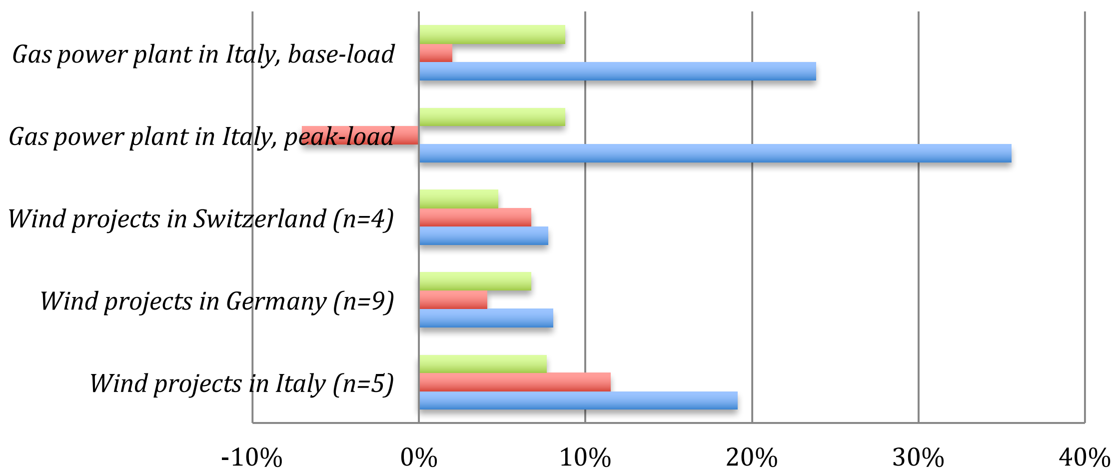
Please refer to appendix 1.1 and 1.2 to find more details on specific parameters used for the calculations.

[9] We consider all the announced, financed, permitted and commissioned projects between 2004-2015 for this analysis.

The results of our cross-case study analysis show high expected return rates on gas projects (up to 35% for a plant intended for peak demand) and lower ones for wind energy projects (see figure 9).

However, the realised rates of return for gas projects are significantly lower than expected ones and than the hurdle rate applied to these investments. The main reason for this mismatch is the low demand and lower operating hours of the plants than planned by investors. Since investments in these gas projects were done at the time of increasing renewable energy generation, they ended up not having enough demand in order to sell the produced electricity at attractive prices. Currency risk also affects the returns – as a result of annual cash flow conversions from Euros to Swiss Francs the IRR is reduced by 1 to 3 percentage points.

In case of renewable energy projects, realised returns differ less from expected returns compared to the case of gas projects. However, one can still observe the mismatch between expectations and reality in locations outside Switzerland. Much of the variation is due to wind conditions being worse than expected.



	Wind projects in Italy (n=5)	Wind projects in Germany (n=9)	Wind projects in Switzerland (n=4)	Gas power plant in Italy, peak-load	Gas power plant in Italy, base-load
Hurdle rate	8%	6.75%	4.75%	8.80%	8.80%
Realised return	12%	4.09%	6.75%	-7%	2%
Expected return	19%	8.05%	7.75%	35.54%	23.83%

Figure 9. Summary of cross-case study analysis results

Policy risk seems to affect the overall investment amounts, even if no unexpected retrospective changes to specific support schemes occurred in 2014-2015 (see figure 10). Although investments in Germany do not offer higher return rates than investments in other locations, the amount of investments in Germany is higher than in Italy and higher than in Switzerland. The Italian green certificate scheme has been offering quite attractive returns, but only 12% of the Swiss companies that invest in wind energy did so in Italy. One explanation for this phenomenon could be that investors perceive the German feed-in tariff support scheme as a less risky policy compared to the Italian green certificates-based support scheme. In the meantime, Switzerland also has a feed-in tariff support scheme and the return rates on realized wind projects in the two countries are similar. Nevertheless, 42% of investors do wind business in Germany and only 8% in Switzerland (see figure 10). One reason for this could be the size and liquidity of the German market. However, there could also be perceptional factors, which may affect evaluation of investment opportunities at home and abroad. To find out what these factors are, we supplement our research with focus group discussions and interviews.

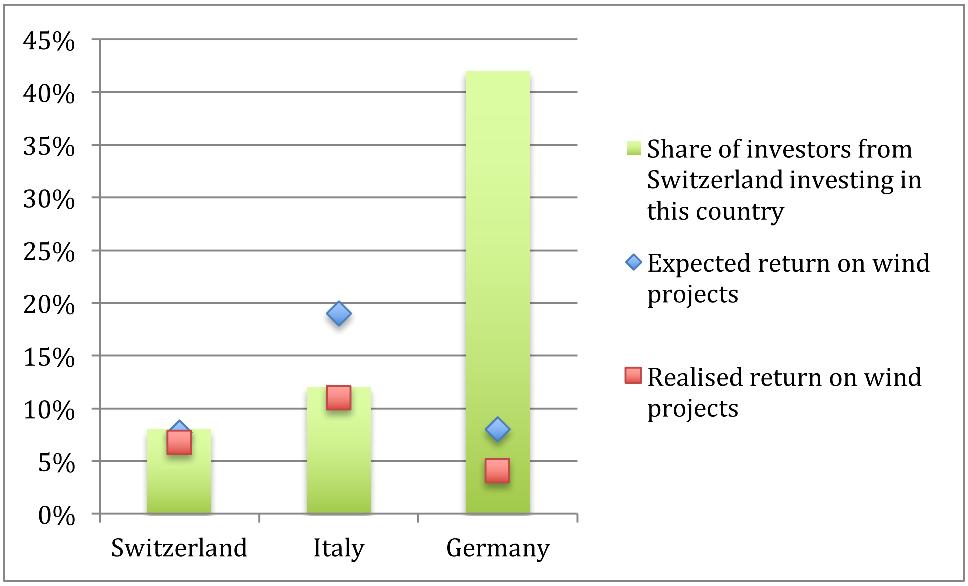


Figure 10. Share of investors vs. expected and realised rates of return

2.3.4. Factors affecting the choice of location for future projects

Focus group discussion results

12 people formed the focus groups of 6 people each. 10 of them were from Switzerland, 1 – a Swiss working in London, and 1 – a Ukrainian with a residence in Constance. 4 participants were representing utilities, 2 - project developers, 3 - institutional investors, and 3 were from academia. This means 9 professional investors and 3 academia representatives. 10 participants were male and 2 female. The groups were asked the following question: "Imagine you can invest in a 12 MW wind park. Which of the following locations would you choose for your investment? Answer options: Italy, Germany, Switzerland, other location". The two groups came up with investment options in the following countries: Norway, Finland, Ukraine, South Africa, Egypt, Morocco. Participants briefly mentioned the option to invest in Switzerland, but immediately dismissed it mentioning permitting issues. During the talk, participants often first referred to emotional arguments, such as "big opportunities", later justifying the suggested options by highlighting factors such as costs, political stability and feed-in tariff or other policy. The final choices were Finland and Norway with expected returns in the range of 7-9%.

Interview results

In April and March 2017, we used a similar question as an experimental choice task during 12 expert interviews conducted in person. Having discovered that returns may be equal in Switzerland and in Germany, we reduced the choice to two options: an investment project in Switzerland and another one in Germany. We provided information about project type, size, business model (permitting risk excluded), cost, annual production, and policy support.

Technology, cost and business model were the same in both cases, meaning investment of CHF 16.7 million in a turnkey wind onshore power plant, generating profits from operating it and receiving compensation through a feed-in tariff. While the level of the feed-in tariff differs, as well as the size and the annual production, the cash flows that could be projected using these parameters are exactly the same. The decision makers saw the data without pre-calculated cash flows and were encouraged to think aloud while making their experimental investment decision (see the two projects provided as choice options in figure 11)

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Imagine, you have to choose between two investment options. Which of the two projects would you choose?

	Project A	**Project B**
Technology	Wind onshore	Wind onshore
Business model	Only operation, development and construction outsourced	Only operation, development and construction outsourced
Location	Germany	Switzerland
Feed-in tariff	CHF 90/MWh for 20 years	CHF 215/MWh for 20 years
Overall project cost	CHF 16.7 mln	CHF 16.7 mln
Project size	12 MW	6 MW
Annual Production	26,280 MWh	11,038 MWh

If you are not sure, please, explain what would you do to come to a decision, which additional information/equipment do you need.

Figure 11. A sample of the experimental question

Further, additional questions were asked about factors affecting the location choice and risk premium used for different locations, namely: 1) preferred technology; 2) preferred project stage for involvement; 3) preferred project size; 4) preferred country; 5) evaluation method used; 6) minimum hurdle rate on the project; 7) use of risk premium for different locations; 8) range of risk premium; 9) importance of individual calculation components for risk premium estimation; 10) perceived “safest” policy; 11) test question for knowledge of specifics of the feed-in tariff calculation in Germany and Switzerland.

Interviews were recorded and transcribed with the help of an external transcription service.

Several interview partners, faced with the choice, opted for German project first, explaining their choice by (a) its bigger size, which might be associated with higher returns beyond the 20-year period of the guaranteed tariff; (b) its lower riskiness, as the feed-in tariff felt for them more secure in Germany than in Switzerland; (c) business connections and previous experiences in the given region, allowing to save on annual costs and benefit from economies of scale. This group then suggested that they might still do the project in Switzerland for “political” or “qualitative” reasons, since they represent domestic companies and are supposed to participate in the Swiss energy transition. A few other interview partners attempted to do the calculation right away and suggested that if the return is really the same, they would do the project in Switzerland for "political" reasons, pointing out to responsibility to participate in the local energy transition. In the meantime, the same group mentioned that if the project was still in the development stage, they would have to consider "qualitative" risk factors in Switzerland and would rather opt for Germany. By qualitative risk factors they meant long administrative procedures for acquiring construction permits rather than the issue of social acceptance. The interview partners felt that the levels of social acceptance are similar across Europe, but in other places than Switzerland either the processes take less time or the projects are bigger to allow a higher return rate to compensate for capital invested in the process. The discussion about permitting occurred despite the fact that the suggested projects were defined as ready to operate. In the meantime, once faced with the question about feed-in tariff compensation in Switzerland, interview partners felt it was adequate and did not claim that they would expect it to compensate for the risks associated with qualitative factors.

Thereby, interview partners used "qualitative" arguments when discussing investments in Switzerland, and "quantitative" arguments when discussing investments abroad. Classifying risks as "qualitative" implied a binary categorization of those risks as being either acceptable or unacceptable, rather than a more finegrained approach of trying to quantify an adequate risk premium for compensation of the respective risks.

Table 8. Work Package 2: Overview of the completed work and findings

Research Question	Methodological Approach	Main Findings
Which part of past Swiss power generation investment happened domestically vs. abroad and what were the preferred project types?	Research via Bloomberg New Energy Finance database	• Between 2004-2015, 69% of new investment in energy projects was allocated abroad and only 31% in Switzerland. • The preferred project types were hydro (30%), wind (30%) and gas (25%). • While most of the hydro projects were implemented in Switzerland (83%), the majority of wind (92%) and gas projects (88%) were implemented abroad. • Most popular investment destinations besides Switzerland were Germany (42% of wind projects) and Italy (22% of gas projects and 12% of wind projects).
What were the return expectations for the preferred project types, and how did the realised investments perform financially?	Cross-case study analysis on selected gas and wind projects. Data collection and calculation of returns; 5 interviews to validate assumptions and results. Main assumptions: a) For expected returns – electricity and fuel price of the investment year stay constant and the production volumes fulfill declared expectations; b) For realised returns – realised production volumes, electricity and fuel prices. For the upcoming years of operation, parameters from 2015 stay constant.	• Expected returns on gas projects were higher than on wind projects; realised returns on wind projects were higher than the ones on gas projects • Expected returns on wind projects abroad were higher than the ones on wind projects in Switzerland. • While realised returns on the analysed wind projects were lower in Germany than in Switzerland, 42% of Swiss investors in wind energy chose projects in Germany and only 8% in Switzerland.
Which factors influence decision-making about investing in CH vs abroad?	2 focus group discussions; 12 interviews including an experimental choice task between an investment project in Switzerland and another one in Germany, with information provided about project type, size, business model (permitting risk excluded), cost, annual production, and policy support.	• Part of the interview partners focused on the calculations, another part on single parameters such as project size or the level of the feed-in tariff. • Decision-makers referred to arguments about financial profitability more often in the case of Germany, and arguments about social responsibility and political reasons when talking about investments in Switzerland.

2.4 Limitations and future Research

Our research on expected and realised risk-return profiles of power generation investments is a subject to a number of limitations, which represent useful starting points for future research.

First of all, data availability issues limited the scope of our cross-case study analysis to a few wind and gas power projects. Future research may benefit from access to data on a larger sample of such cases to gain more detailed insights for different project locations.

Second, we understand that there must have been favourable predictions for specified investments at the time of making respective decisions, such as growing energy demand and growing energy prices. Nevertheless, due to data availability limitations, we had to rely on the assumption about market conditions staying constant since the investment year. Access to the historical data about the predictions of the electricity and fuel prices by country could allow future research to validate our results and provide more details on the factors affecting investment decisions. Similarly, we had to estimate several cost and revenue parameters for the analysed projects, using publicly available data. Future research could benefit from direct access to company data.

Furthermore, while we initially aimed at getting a sense for the risk premium that Swiss investors would seek in order to be compensated for domestic risks, we found that they rather resorted to a qualitative risk assessment when it comes to investing in Swiss projects. Future research could use surveys to incentivize respondents to disclose their expectations in a quantitative manner, and thereby increase generalisability.

WP3: Dream team or strange bedfellows? Complementarities and differences between electric utilities and institutional investors in Swiss hydropower[10]

Abstract

Institutional investors can potentially be a significant source of capital for financing the transition to a low-carbon electricity system. This is even more important as incumbent utilities in many European countries are struggling to adjust their business model to changing market conditions. As utilities are cutting their capital expenditure programmes, can institutional investors like pension funds step in and close the financing gap? This article reports on a choice experiment with pension fund and utility managers conducting 1,129 experimental investment choices in Swiss hydropower plants. We find that complementarities exist with regard to financing different stages of project development – pension funds are averse to construction and development risk but are comfortable deploying capital to existing projects, while utilities are willing to invest in all stages of a project. The two groups show surprising similarities in their aversion to fluctuating electricity prices. When fully exposed to revenue risk, utilities and pension funds demand a risk premium of 5.98% and 7.94% respectively. For policy makers, this suggests that shielding investors from revenue risk, as has been done with feed-in tariffs for other renewables, might be an effective way of lowering the financing cost of hydropower. When it comes to their preferred co-investors, the two groups express mutual distaste for each other: Utility managers would rather invest in consortia with other utilities, and the same goes for institutional investors.

Keywords: choice experiment; capital cost; renewable energy; hydropower; investment decision; business model;

[10] The content of this chapter is currently under review in *Energy Economics* and has been part of Sarah Salm's dissertation at the University of St. Gallen (2017).

3.1. Introduction

The transition towards a low-carbon energy system requires mobilizing significant capital flows to finance renewable energy projects. The Organisation for Economic Cooperation and Development (OECD) estimates that current global energy investment levels have to be doubled to about United States Dollar (USD) two trillion per year or two per cent of gross domestic product (GDP) (Kaminker & Stewart, 2012). Institutional investors, who manage USD 71 trillion in assets, may potentially play an important role in providing the required capital (Nelson & Pierpont, 2013). It has also been pointed out that there may be a good match between the long investment horizon of institutional investors, such as pension funds, and the typical cash flow profile of energy infrastructure projects such as hydropower (Spreng *et al.*, 2001). In addition, the current low-interest environment is leading institutional investors to watch out for new asset classes that promise steady long-term income streams (Kaminker & Stewart, 2012). In fact, looking at who is financing new renewable energy capacity, there are signs for an increasing investor diversity, with non-energy investors accounting for a large share of ownership in renewable energy assets (Bergek *et al.*, 2013). For example, more than 95% of solar photovoltaic assets in Germany are owned by either institutional or retail investors (Helms *et al.*, 2015). In the case of larger renewable energy projects, such as hydropower, this trend is less pronounced (Chassot, 2012). The current liquidity situation of incumbent utilities, however, is under severe pressure in many European countries (Economist, 2013), raising the question whether institutional investors can contribute to closing the gap and playing a more important role in financing large-scale renewables in the future.

The current paper provides an empirical answer to this question by reporting on results of a choice experiment with 53 investment professionals from incumbent utilities[11] and pension funds in Switzerland, conducting 1,129 experimental investment choices. By surveying risk preferences of professional investors, we add rich empirical evidence to the academic debate about investor diversity and energy investment decision-making. Our aim is to test the common implicit assumption that pension funds are willing to finance renewable energy projects at lower cost of capital than utilities, and to get in-depth insights into the relative preferences of both investor groups with regard to different stages of project risk, electricity price risk, technology, and investment consortia.

The remaining part of this chapter is structured as follows: The next section reviews relevant literature and presents the research hypotheses. Section 3.3 discusses our methodology. Section 3.4 presents the results of the choice experiment. Section 3.5 concludes the chapter with a summary, limitations and suggestions for further research.

[11] The terms “electric utility”, “incumbent utility”, “utility company”, and “utility investor” are used interchangeably within this chapter.

3.2. Theory and hypothesis development

To determine the differences in the risk-return perceptions of incumbent utilities and pension funds towards renewable energy investments, we subsequently review relevant literature and state hypotheses around major influence factors.

Investor-specific differences in risk-return perception

Most of the theoretical concepts in investor-specific risk-return perception use variations of Bentham's utility theory (see Section 3.3.2). As these concepts primarily address consumer behaviour, Markowitz transferred this theory to the institutional investment domain, explaining that investors who accept a higher level of risk should be compensated by proportionally higher returns. This theory represents the groundwork for further research into investor-specific variations in perceived risk and return (Farrelly & Reichenstein, 1984; Gooding, 1975; Koonce *et al.*, 2005), which is receiving significant attention in recent energy-related research. In research practice, several streams investigate investor-specific investment behaviour (Stenzel & Frenzel, 2008). The influence of past activities on present decisions is characterised by the concept of "path dependency", which is often called upon to explain the lock-in of utility companies to fossil-based technologies (Unruh, 2002; Wüstenhagen & Teppo, 2006). Further, "dynamic capabilities" describes the lag in adapting existing resources to new market conditions (Bergek *et al.*, 2013; Langniss, 1996; Masini & Menichetti, 2012; Stenzel & Frenzel, 2008). Another rather financially-driven concept that is highlighted by Helms *et al.* (2015) is "capital cost dependency". It explains why some investors expect high returns that they have previously generated in fossil-driven businesses, and, consequently, expect the same return from lower-risk renewable energy projects. Salm *et al.* (2016) found evidence for investor-specific risk-return expectations through a segmentation analysis by discovering two types of renewable energy retail investors: "local patriots" and "yield investors". Following previous argumentation on investor-specific risk-return expectation and the late interest of utilities to invest in renewable energy, we are interested to test the subsequent hypothesis:

H1: Pension funds are willing to finance renewable energy assets at lower cost of capital than incumbent utilities.

The choice of investment partner

Many companies build partnerships to benefit from knowledge, information or financial contribution that would otherwise not be accesable. Existing research largely confirms the beneficiary nature of cooperation for companies, particulary in the financial industry.

Lerner (1994), for instance, found that venture capitalists (VC) prefer to invest in a consortium with the same category rather than investing on their own. It enables VCs and other professional investors to spread financial risk, establish long-term partnerships and at the same time exchange valuable industry experience, contacts and resources (Bygrave, 1988; Cai

& Sevilir, 2012; Lerner, 1994). Important information could also contain the signal whether cooperation partners would pursue a particular investment opportunity. Especially, in situations with high uncertainty such information possess enormous value (Sah & Stiglitz, 1986; Wilson, 1968). Tian (2012) added to the discussion that VC firms cooperating in syndicates are more successful throughout the entire engagement process. Their portfolios are performing better and achieve higher prices upon their exit. This phenomen is further refelected in professional investors' access to cooperation networks: the more they are connected to their investment within a social (Cohen *et al.*, 2008) or professional network (Cai & Sevilir, 2012), the better the performance and / or value creation of their investments (Hochberg *et al.*, 2007). Contrasting cooperations with partners of the same category, Sorenson and Stuart (2001) suggested that cooperations across industries and regional boundaries are of major importance. Partners with different backgrounds potentially have complementary knowledge that enables a more balanced view on an investment opportunity (Bygrave, 1988; Gorman & Sahlman, 1989; Sahlman, 1990). In addition to supporting the beneficial role of cooperations across sectors, Gompers *et al.* (2016) found significance that partnerships of the same cateorgy harm a company's portfolio performance. It may lead to sticking in social conformitiy and less critical questioning which results in rather inefficient decision-making (Ishii & Xuan, 2014; Uzzi, 1996). We thus state the following hypothesis:

H2: Given their complementary capabilities, utilities and pension funds should prefer investing in consortia with the other investor type.

The moderating influence of experience

Measuring the influence of experience on future developments has been investigated within a wide range of subjects, including foreign direct investments, organisational acquisitions, new product launches and renewable energy decision-making. It has primarily been examined with respect to positive business performance as an answer to previous experience and potentially subsequent decision-making.

Given an investigation of foreign investments entering the United States, Mitchell *et al.* (1994), Li (1995) and Shaver *et al.* (1997) argued that foreign direct investments are more likely to survive for companies with prior experience in their host country. On a more general base, this was further confirmed by Johanson and Vahlne (1977) and Perkins (2014) who pointed out that multinational companies with experience in similar-structured countries, are more likely to operationally succeed in foreign countries. The influence of experience has further been investigated with respect to organisational acqusitions indicating that companies with previous experience drive post merger operations more succesfully (Brauer *et al.*, 2014; Hayward, 2002). For product launches in new markets, Brady and Davies (2004) and Hoang and Ener (2015), among others, added that prior experience with technology and new product markets is positively associated with the later performance of such products. Following the rationale of the previous success stories, behavioural finance literature as of Agnew and Szykman (2005) revealed that future decisions are derived from past experience, particularly for situations where confronted with many new information, investors rely on their experience. This was further verified by Masini and Menichetti (2012, 2013) who found that investors with previous renewable energy experience are more likely to invest in renewable energy than those without prior experience. Following the discussed influence of experience on investors' decision-making and subsequent success, we are particularly interested to see whether electric utiltities, that are mostly experienced with investments in renewable energy technology, are more likely to be operationally involved in such projects than pension funds. Thus, we state the following hypothesis:

H3a: Not having relevant industry experience, pension funds are more risk-averse than utilities with regard to operational risk.

Further, we are interested to examine whether previous experience positively impacts the risk friendliness towards electricity price risk, leading to the following hypothesis:

H3b: Not having relevant industry experience, pension funds are more risk-averse than utilities with regard to electricity price risk.

The technology preference

The increase of non-dispatchable renewable energy in Europe has fundamentally changed the energy supply landscape, demanding for new business models that are both flexible and economically viable (Helms, 2016; Helms *et al.*, 2015; Loock, 2012).

Particularly the development of storage systems has emerged in recent years, to store excess renewable energy in peak hours and bridge the supply gap whenever there is a lackage of sun or wind power. Consequently, storage systems seem to be a very promising solution to guarantee for continuous power supply in an energy system dominated by renewable energy capacity (Black & Strbac, 2007; Després *et al.*, 2017; Ibrahim *et al.*, 2008; Scorah *et al.*, 2012). In contrast to hydrogen, compressed air or battery storage systems, hydropower storages are a proven and yet scalable technology (Ibrahim *et al.*, 2008; Yang & Jackson, 2011). They have often been discussed in combination with non-dispatchable technology such as wind or solar photovoltaic installations. Mostly, previous research determined cost and / or resource efficient employment of renewable energy and hydropower storage capacity through optmisiation models for several European countries (Benitez *et al.*, 2008; Bueno & Carta, 2006; Jiang *et al.*, 2012; Kapsali & Kaldellis, 2010). A smaller stream of research investigated if country-specific framework conditions support a joint application of storage and renewable energy technology (Dursun & Alboyaci, 2010).

Although wind and solar photovoltaic capacity penetration is rather small in Switzerland, electricity market integration and cooperation on a European level could help neighbouring countries such as Germany and Italy to store their electricity without building additional storage capacity (Creti *et al.*, 2010; Newbery *et al.*, 2016). Following an increasing electricity market integration within Europe, Swiss hydropower storage investors could benefit from their expertise and store excess energy from neighbouring countries, leading to the subsequent hypothesis:

H4: The growth of non-dispatchable renewables like wind and solar PV increases the value of flexibility, therefore energy investors should prefer storage hydropower plants over run-of-river plants.

This chapter addresses the research gap, thereby simultaneously contributing to important streams of literature on storage technology, choice of investment partner, moderating influence of experience and investor-specific renewable energy decision-making. Additionally, most empirical evidence addresses revealed preferences, but neglects to capture future investment ambitions. As renewable energy markets are moving fast in terms of policy shifts, technological maturity and market participants, it is crucial to adopt a forward-looking perspective. This research effort involves the application of choice experiments with two groups of investors (utility companies, and pension funds) and the collection of real-time information about how different levels of risk affect current and future investments.

3.3. Material and methods

3.3.1. Sample and data collection

The survey describes the choices of 53 managers from Swiss incumbent utilities and pension funds. Corresponding contact details were collected from conference lists, social media platforms and generous internet research. Managers connected to leading positions in either utility companies or pension funds were elicited using keyword searches. We invited survey participants from all company size ranges to participate, and, in the case of pension funds, from different industrial sectors.

Accordingly, 154 incumbent utilities and 246 pension funds were invited by e-mail or private messages on selected social media platforms to participate in our anonymous survey. In the cases that our survey could not be delivered, the related participants were removed from the overall survey sample. Survey participants received two mailings: the initial invitation and one reminder.

In total, 125 managers accessed our survey. Cleaning the sample led to deleting double entries (8), incomplete responses (47) and investors from outside the target categories (3). Further, we included 10 incomplete responses where there was sufficient information for them to be integrated into the final analysis. The remaining survey sample consisted of 67 survey respondents of whom 53 indicated that they would potentially invest in Swiss large-scale hydropower plants. This pointed to an overall response rate of 17%. The response rate and sample size is in line with previous research that has been conducted with professional investors (Chassot *et al.*, 2014; Loock, 2012; Lüthi & Wüstenhagen, 2012; Salm, 2017). The response funnel is illustrated in figure 12.

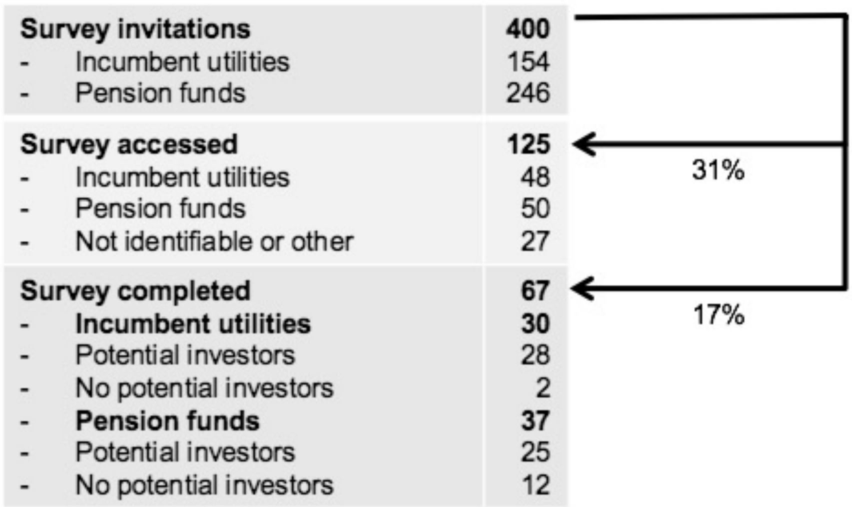


Figure 12. Response funnel of survey sample

The demographic structure of the survey sample is illustrated in Appendix 2. Our survey respondents are mainly male with an average age of 45 for incumbent utilities, and 48 for pension funds. Respondents from pension funds tend to have more years of work experience (20-25 years), but less renewable energy experience (less than 5 years) compared to those from the incumbent utility sample. Firm size tends to be large for the incumbent utility sample (100-499 employees) and smaller for pension funds (10-99 employees).

3.3.2. Choice of methodological approach

We applied a two-step approach, consisting of a qualitative pre-study followed by a quantitative choice experiment. The qualitative pre-study consisted of 11 interviews with the following groups of decision-makers from our target audience: banks, investment and pension funds, utility companies and federal institutions concerned with energy topics. The interviews were conducted in the period between June and October 2015 with major stakeholders of large hydropower investments in Switzerland as part of a Master's Thesis on pension fund investments in Swiss hydropower, in close cooperation with the two authors (Vuichard, 2015).

The choice experiment builds upon the concept of utility theory first introduced by Bentham (Bentham, 1996). More precisely, it was born out of further developments from this initial theoretical development, including discrete choice and random utility theory (Ben-Akiva & Lerman, 1985; Manski, 1977; McFadden, 1980). It assumes that the overall utility of a product or investment consists of several part-worth utilities that are linked to the investments' attributes (e.g. technology, or investment partner).

The approach was first applied in mathematical psychology by pioneers Kruskal and Luce and Tukey (Kruskal, 1965; Luce & Tukey, 1964). Since then, it has conquered diverse fields of research including health (Phillips *et al.*, 2002; Ryan, 1999; Ryan & Farrar, 2000), marketing (Green & Krieger, 1991; Green & Srinivasan, 1990) and entrepreneurship (Muzyka *et al.*, 1996; Riquelme & Rickards, 1992; Shepherd & Zacharakis, 1999). Recently, it has been introduced to the domain of energy research, including renewable energy investment decision-making. Most research in this domain relates to consumer decision-making (Banfi *et al.*, 2008; Goett *et al.*, 2000; Kaenzig *et al.*, 2013; Kaufmann *et al.*, 2013; Murakami *et al.*, 2015; Roe *et al.*, 2001; Sammer & Wüstenhagen, 2006), although an increasing amount of research has successfully applied choice experiments, more specifically conjoint analysis, to investigate the investment decisions of professional investors (Chassot *et al.*, 2014; Lüthi & Wüstenhagen, 2012; Masini & Menichetti, 2013; Ritzenhofen & Spinler, 2014). Generally, conjoint analysis is frequently applied to test immature markets for potentially new product launches over a wide range of areas (Louviere *et al.*, 2000). This approach perfectly matches the target of our research endeavour in a market with a relatively low density of investment data. In contrast, other techniques (e.g. interviews) that require respondents to reconstruct previous activities (Kroes & Sheldon, 1988) often expose a social desirability bias (Gustafsson *et al.*, 2007) and the inability of respondents to fully remember past activities, as well as generate difficulty for respondents in terms of the need to explain previous decisions in comprehensive detail (Golden, 1992).

Over time, conjoint analysis has become more sophisticated as it has adapted to the increasing demands of both practitioners and researchers. Among these advancements are adaptive conjoint analysis (ACA), a rating-based approach, and choice-based conjoint analysis (CBC) and adaptive choice-based conjoint analysis (ACBC) which are full-profile methods. While ACA adapts to respondents' previous choices, thereby creating an interactive survey, CBC creates a more realistic environment in which respondents evaluate competing investment options in parallel. To create a realistic decision environment and enable ongoing adaptation to previous choices, we applied the latest refinement, ACBC, that combines the benefits of both approaches (Johnson & Orme, 2007; Orme, 2009, 2010).

3.3.3. Experimental design

The ACBC was conducted with Sawtooth Software's module SSI in three parts. Within the first and second part we asked survey participants to evaluate screening and choice tasks. After receiving an in-depth description of the project characteristics, survey respondents received the following explanation prior to the screening tasks: *The following survey assumes an investment size of 50 MW (approx. 250 million CHF) and a project lifetime of 80 years on the Swiss energy market. If you wish, you can sell your power plant independently at any time. The given compensation (in %) refers exclusively to the sale of electricity.* Subsequently, respondents were confronted with four hypothetical investment opportunities which they could either accept ("Yes") or reject ("No") over five screening rounds (see figure 13). The four investment options were evaluated independently, meaning that survey respondents could evaluate as many options as required. Overall, respondents evaluated 20 screening tasks. Through use of these screening tasks (namely, by asking respondents which features they consider unacceptable), we were able to detect any non-compensatory screening rules, applied when respondents use simple heuristics in their investment decisions (Orme, 2009).

Total return before taxes	6%	1%	9%	5%
Technology	Storage power plant	Storage power plant	Run-of-river hydro plant	Run-of-river hydro plant
Partner	Consortium with institutional investors	No partner	Consortium with utility companies	No partner
Electricity price risk	50%	0%	100%	0%
Business model	Outsourced development and construction, own operation	Own development, construction and operation	Outsourced development, construction and operation	Own development, construction and operation
	Yes No	Yes No	Yes No	Yes No

Figure 13. Screening tasks in the choice experiment

The subsequent choice task tournament asked survey participants to finally evaluate their previously selected investment options in a competitive environment. This involved selecting the best of three investment options which were simultaneously presented. The process continued until only one winning concept remained (Johnson & Orme, 2007). The third task was for respondents to provide information about their investment behaviour, preferences and personal information including gender, age, work and investment experience, and company size.

The investment opportunities were based on five attributes that were previously determined from a literature review and in-depth interviews. They included: “total return before taxes”, “technology”, “partner”, “electricity price risk”, and “business model” (see table 9). The attribute total return before taxes was defined as a continuous pricing attribute rather than by using attribute levels. This means that the price of the presented investment options varied within a pre-defined range (between 1% and 11%). As a consequence, we obtained accurate data for each of the respondents. All remaining attributes consisted of an equal number of attribute levels in order to avoid over- or underweighting of the attributes under investigation. The technology attribute consisted of three types of renewable energy technology, including run-of-river hydro plant, storage and pumped storage power plants. This selection allowed us to investigate whether incumbent utilities and pension funds differentiated between types of technology. The electricity price risk included three degrees of risk (0%, 50%, 100%) which were associated with selling electricity without fixed compensation. This attribute was designed to provide us with valuable insight into how changes in policy, and particularly subsidy design, affect potential power plant construction. The business model attribute described at which stage of the project utilities and pension funds are willing to enter a project, and contained the following three attribute levels: “outsourced development, construction and operation”, “outsourced development and construction, own operation”, and “own development, construction and operation”.

Table 9. Attributes and attribute levels used in the ACBC experiment

Attributes	Description	Attribute levels
Total return before taxes	Return that investor receives on investment	• Pricing attribute between 1% and 11%
Technology	Type of renewable energy technology	• Run-of-river hydro plant • Storage power plant • Pumped storage power plants
Partner	Type of financial partner within renewable energy engagement	• No partner • Consortium with utility companies • Consortium with institutional investors
Electricity price risk	Percentage of output electricity that is exposed to electricity price risk	• 0% • 50% • 100%
Business model	Parts of business that are sub-contracted to a partner	• Outsourced development, construction & operation • Outsourced development & construction, own operation • Own development, construction & operation

3.4. Results and discussion

The following section includes information about the investment background of the survey sample, along with part-worth utilities and average importance scores, the willingness to accept calculation, and a market simulation.

3.4.1. Background information on data and sample

To better understand current and future investment behaviour, it is necessary to examine previous decision-making.

Looking back at former renewable energy investments indicates that the primary investment goals of incumbent utilities were not predominantly financially motivated. The need to replace existing technologies was seen as a primary reason, together with portfolio diversification which was ranked second. Incumbent utilities mainly invested in solar photovoltaics (25%), small hydropower (24%) and wind onshore (18%). Only 13% of their overall investment went to large-scale hydropower. Most of the incumbent utilities indicated that they were previously involved in the development, construction, operation and maintenance (86%) of their renewable energy power plants, while only a smaller fraction (14%) claimed to own power plants on a sole ownership basis (all activities subcontracted out). The survey results indicated that managerial respondents of incumbent utilities still found a favourable return profile to be meaningful in their decision-making, but not a primary determinant. Investments into renewable energy were not seen as a way to avoid the low yields of comparable investments but rather as an opportunity to enter a new and growing market. None of the incumbent utilities considered the importance of contributing to a positive climate balance a primary reason for their selections, although a few utilities considered it a secondary determinant.

In contrast to the high level of engagement of incumbent utilities in the renewable energy sector, most of the pension fund representatives we surveyed had previously refused to invest in renewable energy. Understanding more deeply their reasoning for this creates interesting insight into their motivation compared to respondents from incumbent utilities. Previously, pension funds faced significant uncertainty about the underlying political risk associated with renewable energy investment opportunities, especially when such investments were compared with fixed-income bonds, their main investment category. This fact, together with their lack of relevant expertise, may explain their perception of renewable energy investments as high-risk.

Contrasting previous investment behaviour, our survey results showed that incumbent utilities and pension funds displayed significant interest in making Swiss large-scale hydropower investments. While a high share of incumbent utilities (93%) expressed their interest, pension funds still seemed a little more cautious about pursuing this potentially new investment opportunity (68%). Most incumbent utilities and pension funds likewise preferred investment volumes smaller than 50 million Swiss francs (43%, 64%), or between 50 and 100 million Swiss francs (29%, 28%), with only a minority willing to invest larger volumes. Given the need for significant investment to finance large-scale hydropower plants, collaborations may be one solution for amassing sufficient capital to build up new infrastructure. This opportunity is addressed in the subsequent section of the paper.

3.4.2. Part-worth utilities and average importances

We analysed the ACBC data by means of a hierarchical Bayes (HB) model using Sawtooth Software. The HB model differentiates between an upper (or group) level and a lower (or individual) level to estimate individual part-worth utilities. Individual choices at the upper level follow a single multivariate normal distribution described by a vector of means and a matrix of variance and covariance. More precisely, the HB model complements fragmentary individual data using data obtained from individuals with similar choices. In contrast, data at the lower level describe each individual's choice probabilities through use of a multinomial logit model (Allenby *et al.*, 2004; Orme, 2007; Sawtooth Software, 2016). HB is particularly recommended for the analysis of small data sets such as that generated by our survey when contrasted with other regression tools such as monotone regression (Sawtooth Software, 2016).

As concerns the quality of the HB model, the average root likelihood (RLH) parameter indicates the model fit with the predicted model. Technically, RLH is the geometric mean of all predicted probabilities and is determined by taking the n^{th} root of the probability where n equals the total number of choices taken by all respondents during all tasks. The highest obtainable value is 1 and the lowest 1/k, where k equals the number of choices per average task. As we displayed three choice tasks simultaneously, each had a probability of 33% of being randomly selected, equal to the lowest possible RLH value (.33). For our data the RLH value was high (incumbent utilities RLH=.71, pension funds RLH=.77) which indicated the good quality of the model.

To better compare results, utility estimates within an attribute were converted to a sum of zero. As they are interval data, utility comparisons were only possible within attributes. Zero-centred part-worth utilities, standard deviations and the lower and upper 95% confidence interval are illustrated in table 11.

As expected, our results showed that incumbent utilities and pension funds likewise preferred larger to smaller returns. In terms of technology, incumbent utilities reported a stronger preference for run-of-river hydro plants, whereas pension funds favoured pumped storage hydropower plants. These choices were further reflected in the level of "unacceptable" responses, which was equivalent to the share of participants who stated that the presented attribute levels were ultimately unacceptable for the investment. While only a small share of pension funds rejected making investments in pumped storage hydropower plants under the given conditions (4%), a higher share of incumbent utilities opposed investing in this particular form of technology (10.71%). The heterogeneity of their density distribution (see figure 14) is clearly demonstrated in the fact that the low mean part-worth utility was strongly influenced by a left shift in the curve. As concerns our fourth hypothesis (H4) about the preferred choice of hydropower storage investments, our data showed that only pension funds took storage investments as their first choice. Electric utilities saw higher benefit in run-of-river hydropower plants. This leads to a verification of our fourth hypothesis for pension funds and a falsification with respect to electric utilities. As Swiss utilities were recently involved in a variety of storage projects that became unprofitable through falling prices in peak hours, utilities may stay pessimistic towards further engagement (SFOE, 2013). Pension funds, however, are less influenced by negative experience and may therefore be willing to invest in storage technologies.

Respondents' choices of partner indicated that each group of professional investors strongly preferred to invest jointly in a consortium with investors of the same category. While incumbent utilities stated a preference for initially investing without a partner before building a consortium with institutional investors, the preference of pension funds was clearly to cooperate with utilities instead of investing without a partner. Moreover, the heterogeneous density distribution revealed that a relatively large number of pension funds perceived that the greatest benefit would be accrued in the form of cooperation with a utility. Accordingly, more than half of the representatives of the surveyed pension funds responded that they would refuse to make investments without a partner, in contrast to only 14.29% of the representatives of incumbent utilities. The share of unacceptable responses for partners from a different category was in the single digit range. With respect to our second hypothesis (H2), stating that electric utilities and pension funds should prefer investing in consortia with the other investor type due to complementary capabilities, average part-worth utility values revealed that both investor types clearly preferred to jointly invest with partners of the same category. This supports previous research which claimed the homophily and perceived benefits of single sector cooperation (Bygrave, 1988; Cai & Sevilir, 2012; Lerner, 1994; Sah & Stiglitz, 1986; Wilson, 1968). Moreover, research reporting on the positive perfomance of syndicated investments further support the outcome of our investigation (Cai & Sevilir, 2012; Cohen *et al.*, 2008; Tian, 2012). Consequently, we can not find evidence that electric utilties and pension funds see benefits in a joint project development, leading to a rejection of our second hypothesis.

When it comes to electricity price risk, investors consistently showed a preference for lower rather than higher levels of risk. Approximately one fifth of each investor group rejected investments with a 100% electricity price risk, whereas investments with a 50% electricity price risk were more acceptable. Additionally, the overlapping density distribution of pension funds indicated that these investors were less clear about the differences between a 50% and a 100% electricity price risk compared to incumbent utilities. Both investor groups favoured fully outsourced business models to models with partial or full involvement in development, construction and operation. In contrast to pension funds, incumbent utilities distinguished little between business models. This finding is in line with their low unacceptable rate of 14.29% for fully in-house organised business models, while 56% of the pension funds refused to make investments if they were fully involved in. Our third hypotheses predict that the lack of relevant industry experience lead pension funds to be more risk averse towards operational (H3a) and electricity price risks (H3b). Part-worth utilities and unacceptable levels particularly showed that electric utilities rarely distinguished between different levels of operational risk in contrast to rather sensitive pension funds. A Mann-Whitney U test further confirmed that ($p<.01$) average importances for the attribute business model significantly differed between the two groups, indicating that pension funds put greater emphasis on operational risk and thus being more risk averse. Given the above provided information, our third hypothesis (H3a) can be verified. This is in line with previous research that confirmed professional investors to often rely on their prior experience when making investment decisions (Agnew & Szykman, 2005; Masini & Menichetti, 2013). Previous research signalling the positive effect of experience on the investment outcome may further support our research outcome (Brady & Davies, 2004; Brauer *et al.*, 2014; Perkins, 2014; Shaver *et al.*, 1997). With regard to electricity price risk, a Mann Whitney U-test revealed that both investors aligned in their individual importance ($p>.05$) and rarely differed in their part-worth utilities, which leads to a falsification of the hypothesis (H3b).

Table 10. Average importance scores and standard deviations of attributes

Attribute	Incumbent utilities (N=28) Average importances	Incumbent utilities (N=28) Standard deviations	Pension funds (N=25) Average importances	Pension funds (N=25) Standard deviations
Total return before taxes	33.27**	15.02	19.42**	7.28
Technology type	10.38	5.34	8.93	6.98
Partner	16.77*	10.22	26.50*	14.95
Electricity price risk	20.09	8.61	17.22	7.77
Business model	19.49**	12.08	27.94**	11.51

**p<.01, *p<.05

Subsequently, we calculated average importance scores for each of the previously presented attributes. Average importances were calculated by taking the difference between the part-worth utilities of the most and least preferred level, divided by the sum of differences across all attributes. Table 10 presents the investor-specific average attribute importance scores with their standard deviations. Incumbent utilities and pension funds showed high diversity in their importance scores. While incumbent utilities weighed return-related aspects such as total return before taxes and electricity price risk as the most important attributes (33.27%, 20.09%), pension funds ranked non-financial aspects such as business model and partner highest in importance (27.94%, 26.50%). In contrast, incumbent utilities ranked business model and partner third and fourth in importance, and pension funds total return before taxes and electricity price risk. The investor groups only demonstrated similar interests in the attribute they selected as least important, which was technology. Application of independent Mann-Whitney U-tests indicated that there was a significant difference in average importance values between incumbent utilities and pension funds for all tested attributes ($p<.05$), with the exception of the attributes technology ($p=.226$) and electricity price risk ($p=.269$).

3.4.3. Willingness to accept

In our particular case, the objective of the willingness to accept (WTA) calculation was to link various renewable energy projects to the return that survey respondents demand in return for providing the required capital. This allowed us to understand by how much a respondent would like to be compensated to be equally attracted by a less favourable investment opportunity.

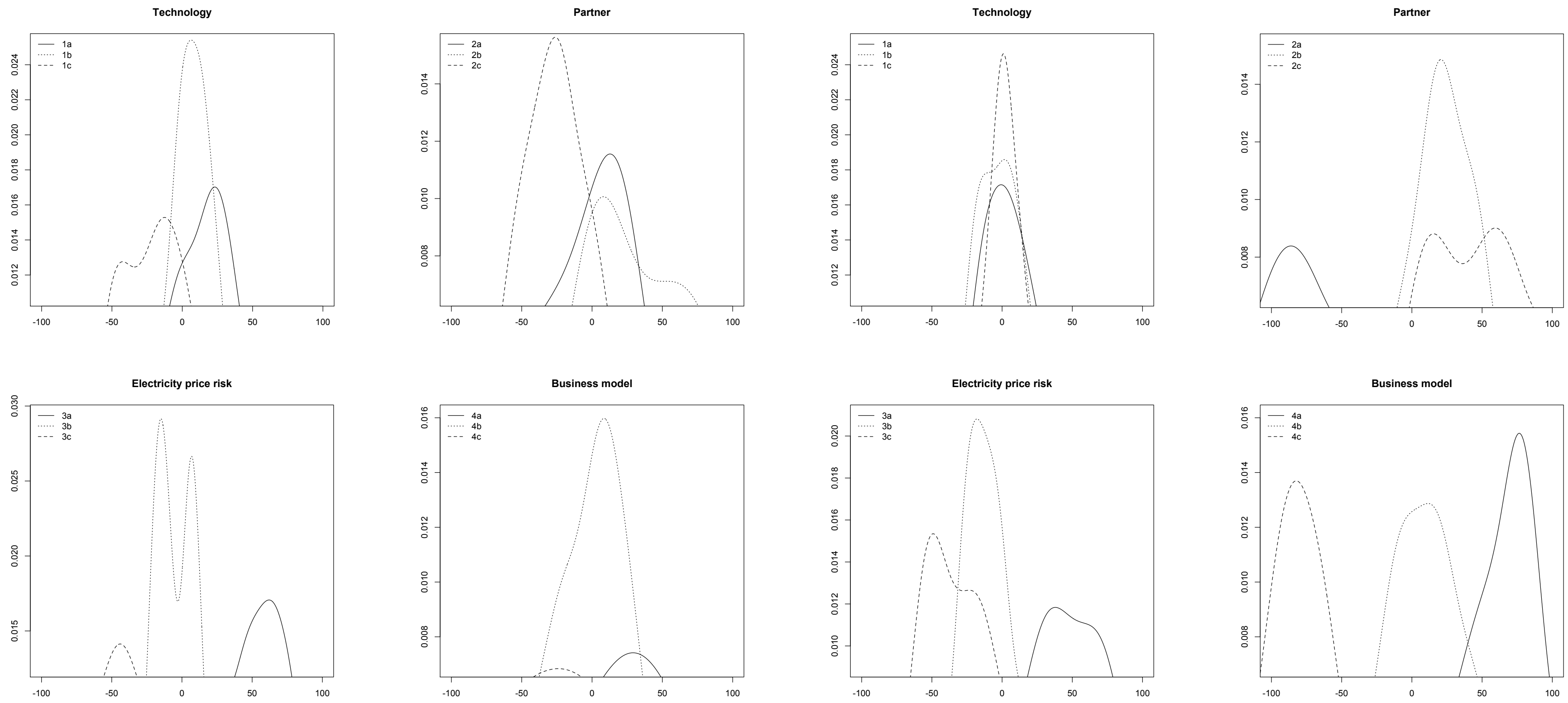
To calculate WTA values, we estimated the WTA aggregated for all survey respondents. This was done by subtracting the lowest possible return (which is 1%) from the highest possible return (which is 11%) and dividing the resulting term (10%) by the difference of their mean part-worth utilities. Accordingly, we converted utility units into an equivalent monetary unit (% risk premium per utility unit). Subsequently, each attribute level was awarded an individual value by multiplying the previously determined % return per utility unit by the difference between the highest part-worth utility of one attribute level and the attribute level that was under investigation. For the highest part-worth utility within one attribute level, the resulting WTA term always equals 0%. This indicates that this option is the most preferred and no additional risk premium needs to be paid on top of the basic requirements. The overall WTA calculation is illustrated in Formula (1).

$$WTA\left(u_{ij}\right) = \left(u_{ij_{max}} - u_{ij}\right) * \frac{p_{max} - p_{min}}{u_{pj_{max}} - u_{pj_{min}}} \tag{1}$$

where u_{ij} equals the mean part-worth utility of attribute i and attribute level j and u_{imax} stands for the highest mean part-worth utility within one attribute level. p_{max} is the highest possible return and p_{min} the lowest possible return. u_{pmax} indicates the mean part-worth utility of the highest possible return and u_{pmin} the cost (price) of the lowest possible return.

Table 11. Zero-centred utilities, standard deviations and lower and upper 95% confidence interval (hierarchical Bayes model with normally distributed utilities)

Number of respondents (N=53)		**HB model incumbent utilities N=28**				**HB model pension funds N=25**			
Attribute	**Attribute levels**	**Zero-centred utilities**	**Lower and upper 95% CI**	**Standard deviations**	**Unacceptable level in %**	**Zero-centred utilities**	**Lower and upper 95% CI**	**Standard deviations**	**Unacceptable level in %**
Total return before taxes	1%	-83.18	[-97.10:-69.27]	37.55		-48.54	[-55.67:-41.40]	18.20	
	11%	83.18	[69.27:97.10]	37.55		48.54	[41.40:55.67]	18.20	
Technology type	Run-of-river hydro plant	14.66	[6.78:22.55]	21.29	0.00	2.82	[-9.17:14.81]	30.59	4.00
	Storage power plant	7.46	[2.29:12.63]	13.96	0.00	-6.22	[-14.22:1.79]	20.42	4.00
	Pumped storage power plant	-22.12	[-29.96:-14.28]	21.16	10.71	3.40	[-5.29:12.08]	22.16	4.00
Partner	Consortium with utility companies	37.72	[23.36:52.08]	38.77	0.00	22.43	[11.02:33.83]	29.09	4.00
	Consortium with institutional investors	-26.74	[-35.01:-18.47]	22.31	7.14	50.35	[36.39:64.30]	35.61	0.00
	No partner	-10.98	[-23.77:1.81]	34.53	14.29	-72.77	[-91.42:-54.13]	47.57	56.00
Electricity price risk	0%	52.36	[45.07:59.64]	19.66	0.00	45.03	[33.29:56.77]	29.94	0.00
	50%	-5.20	[-9.67:-0.74]	12.05	3.57	-13.03	[-20.17:-5.88]	18.23	4.00
	100%	-47.16	[-56.81:-37.50]	26.06	17.86	-32.00	[-40.75:-23.26]	22.32	28.00
Business model	Outsourced development. construction and operation	2.29	[-18.87:23.46]	57.14	17.86	62.89	[50.87:74.91]	30.66	0.00
	Outsourced development and construction. own operation	-0.27	[-8.63:8.10]	22.58	7.14	8.23	[-2.65:19.11]	27.76	20.00
	Own development. construction and operation	-2.03	[-23.98:19.93]	59.28	14.29	-71.12	[-87.16:-55.08]	40.92	56.00



Zero-centred part-worth utilities

<u>Technology</u>	<u>Partner</u>	<u>Electricity price risk</u>	<u>Business model</u>
1a Run-of-river hydroplant	2a No partner	3a 0%	4a Outsourced development, construction and operation
1b Storage power plant	2b Consortium with utility companies	3b 50%	4b Outsourced development and construction, own operation
1c Pumped storage power plant	2c Consortium with institutional investors	3c 100%	4c Own development, construction and operation

Figure 14. Density distribution of attribute levels

The WTA analysis indicated that the risk premium for changes in technology was rather small, leading to the highest premium for utilities to invest in pumped storage power plants (2.21%) and for pension funds in storage power plants (2.21%). Professional investors had similar interests concerning their preferences for cooperating with a partner of the same category. All else being equal, utility companies demanded an additional 3.87% risk premium for cooperating with institutional investors, while pension funds only required an extra 2.88% for cooperating with utility companies. While utilities (figure 15) distinguished little between investors of the same type or the situation of having no partners, pension funds required a risk premium of almost 12.68% in the case that no partner was available. As for the electricity price risk, an increase to 50% and 100% needed to be compensated for by additional returns of 3.46% and 5.98% for utility companies and 5.98% and 7.94% for pension funds. While both groups of investors demanded low risk premiums for operating their own power plants, investors' opinions largely diverged when it came to being involved in the development stage. The high premium (13.80%) pension funds required to compensate them for managing all activities in-house revealed that they perceived the risk of this option to be high, compared to utility companies (0.26%). Within our first hypothesis (H1), we tested whether pension funds are willing to finance renewable energy assets at lower cost of capital than incumbent utilities. Overall, it seemed as pension funds are a promising source of capital. Both investor groups showed nearly aligning return requirements with respect to technology and electricity price risk. However, pension funds were very sensitive to risks associated with the development and construction of power plants as well as with being the only investor. Consequently, pension funds could provide greater liquidity to large-scale projects and complement, but not substitute, electric utilities. Thus, the first hypothesis can be falsified.

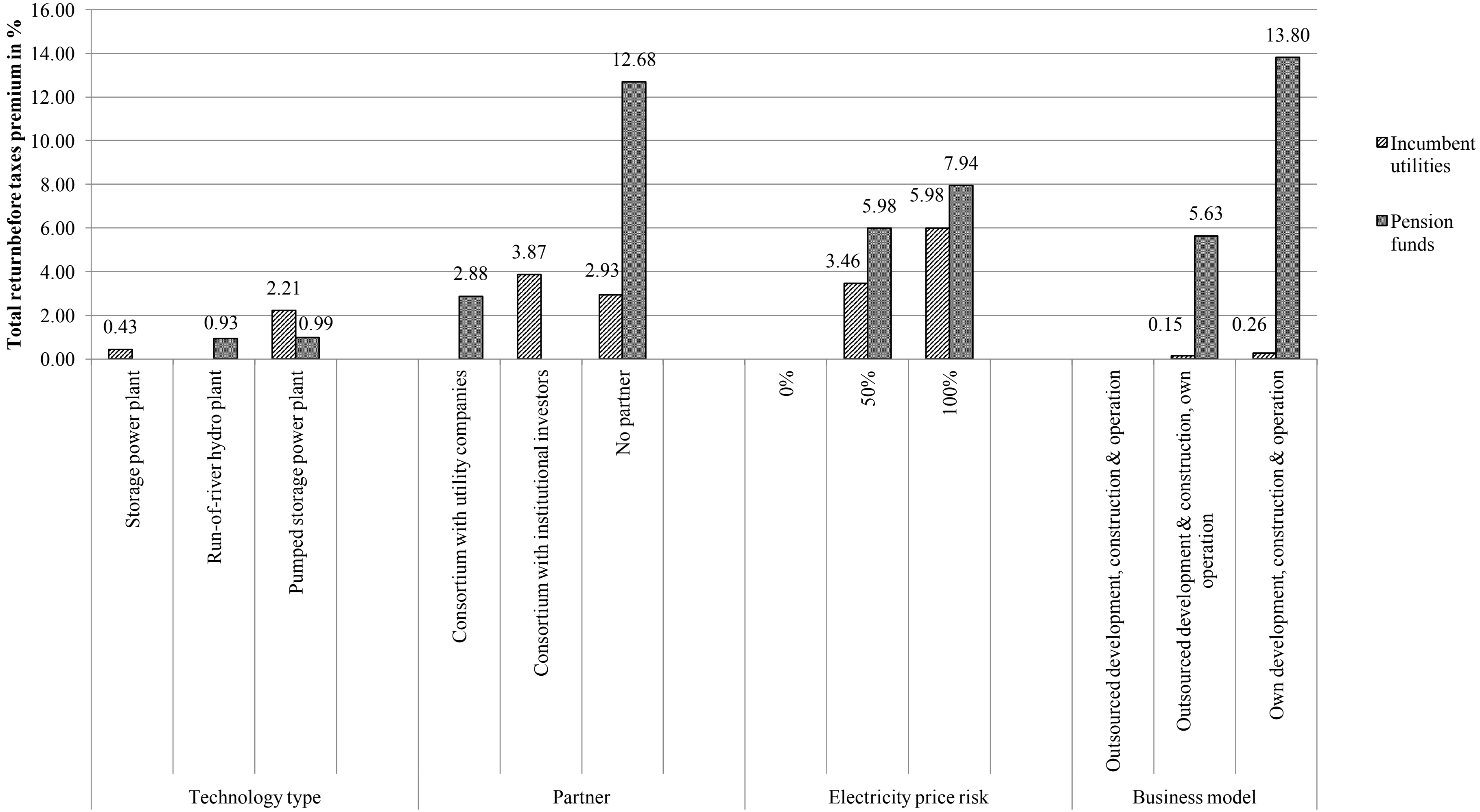


Figure 15. Willingness to accept calculation for incumbent utilities and pension funds.

3. 5. Conclusion

This chapter has contributed to the emerging research stream concerning renewable energy investment decision-making and adds value by empirically exploring the relationship between risk perceptions and required return. The research described herein was designed to answer the research question whether pension funds are able to finance Swiss large-scale hydropower plants at a lower rate of return than incumbent utilities. The findings create a solid foundation for policy makers' decisions to facilitate institutional investment in hydropower.

Our research has illustrated that the investment preferences of incumbent utilities and pension funds largely diverged for factors that were related to experience (partner, business model) and converged for other factors (technology, electricity price risk). With respect to the attribute technology, incumbent utilities indicated a slight preference for run-of-river hydro plants while pension funds saw greater benefit in investing in pumped storage power plants. Both types of investors signalled that having a partner from the same sector was clearly their first choice. In contrast to incumbent utilities, pension funds required a high premium (12.68%) for non-syndicated investments. As for electricity price risk, both investor types showed similar levels of risk aversion. While incumbent utilities differentiated little between business model options, pension funds showed a clear preference for fully outsourced business models. If they were forced to take development, construction and operational risk, they asked for a 13.80% premium, in contrast to incumbent utilities that required only 0.26%.

Our research findings have important implications. Our survey has revealed that pension funds are not, by default, lowering the financing costs of Swiss large-scale hydropower plants. These investors are capable of and willing to inject substantial capital into Swiss hydropower projects, but demand a high risk premium for some specific project characteristics. Pension funds are particularly interested in participating in syndicated investments without taking full responsibility for the development, construction and operation of such power plants. Although pension funds clearly prefer to work in partnership with their peers, a logical consequence of their aversion to operational risk seems to be co-investing with an experienced partner from the utility industry who takes control of overall project development. Such co-investments between utilities and institutional investors could ultimately lead to consortia that leverage the complementarities of both investor types and improve the financing situation for hydropower. Policy makers who wish to support this goal should encourage dialogue between investor groups to increase trust and enhance partnerships to promote large-scale hydropower investment. There are some limitations to our research that can be the starting point for further research on this important and timely topic. The first of these refers to our use of stated preference methodology and the challenges of obtaining a large sample when surveying professional investors. We decided to base our research on stated rather than revealed preference approaches for three major reasons: (1) we wished to investigate pension funds as a potentially new source of investors with a scarcity of historical data, (2) based on the assumption that renewable energy market and policy design as well as technology experience has enormously changed, we sought to examine present and future rather than past investment decisions, (3) valuing preferences for components of the renewable energy project (e.g. business models, electricity price risk) is particularly interesting for the development of future policy design. Nevertheless, it will be interesting to see if future research based on revealed preferences can confirm our findings. Secondly, we conducted this research in the context of large-scale hydropower plants in Switzerland. Although the significant share of hydropower in the electricity mix and the current debate about involving institutional investors in the financing of hydropower plants makes Switzerland an excellent context for our research endeavour, it would certainly be interesting to see if our findings are transferrable to other countries with a high share of hydropower in their electricity mix, such as Austria, Sweden and Norway.

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Appendices

Appendix 1.1. Cost Estimation for Italian CCGT power plants

Type of cost	Data source	Estimated value
Investment costs	Company financial and annual reports	CHF 230,000,000 or EUR147,784,200 for 200 MW (25% share) according to the historical exchange rate from oanda.com on 01.01.2006
Fixed annual costs	Estimated by italian energy consultancy Ref-e (Canazza, 2015).	€34,000/MW installed or €6,800,000 per year for 200 MW
Annual variable costs = (Commodity costs + CO2 costs)*Production Volumes		
$Commodity\ costs = \frac{(Pc + Pt) * 1.1(to\ account\ for\ 10\%\ thermal\ losses)}{E}$		
Pc - Annual commodity price	Up to 2011 the value is estimated using the ITECccgt index (already includes transport cost and efficiency rates at CCGTs); since the market liberalization, the Italian gas balancing platform PBGAS G+1 provides a publicly available source for information about gas prices starting from 2012.	Varies by year
P_t - Cost of transporting each MWh of gas to the turbine	Depend on the transport fees approved by the Italian Energy Regulator and are applied to users that withdraw gas from the high-pressure grid (AEEGSI, 2015).	On average – 0.6 EUR/MWh
E – Efficiency rate of the power plant	Company's media communications	57%
CO2 costs = CO2 production by the plant* CO2 price		
CO2 production by the plant	Publication by the operator	0.388 tCO2/ MWh
CO2 price	Annual prices starting from 2008 published at EEX (EEX, 2016); for the 2006 from historical data on investing.com[12].	Varies by year
Production Volumes	Annual company reports	Vary by year

[12] https://www.investing.com/commodities/carbon-emissions-historical-data

Appendix 1.2. Revenue Estimation for Italian CCGT power plants

Revenue type	Data source / Data analysis approach (when relevant)	Estimated value
Wholesale market prices (MGP)	• Source: historical statistical excel spreadsheets for the years 2006-2015, provided by the electricity market operator - Gestore del Mercato Elettrico (GME, 2016). • For each year, we filtered the data by: a) bidding zones where the plant is located (there are 10 in Italy, in our case NORD and CSUD are applicable); b) the hours with prices higher than the variable operating costs of the respective CCGT; c) for peak power plant – added additional filters to only include hours between 8:00 and 20:00. • Computed the averages of the filtered data to estimate the selling price of the electricity in the operating hours of the plants • Multiplied the estimates of selling prices by the production volumes provided in the company's annual reports.	Varies by year
Balancing/ancillary services to the grid operator (MSD)	Estimates for a 800 MW plant by Italian industry association (Confindustria., 2015). For smaller plants (shares) estimations are reduced proportionally.	For a 800MW CCGT, €15 million
Capacity payment since 2004 (Art. 5 of legislative decree 379/03).		For a 800 MW CCGT, €2 million

Appendix 2: Demographic data of WP3 survey sample

Variable	Value	Incumbent utilities (N=26)	Pension funds (N=31)
Gender	Female	0%	16%
	Male	100%	84%
Age	18-29	0%	0%
	30-49	62%	52%
	50-64	38%	45%
	65-99	0%	3%
General work experience			
	Less than 5 years	4%	0%
	5 to 10 years	15%	3%
	10 to 15 years	15%	10%
	15 to 20 years	15%	16%
	20 to 25 years	23%	26%
	More than 25 years	27%	45%
Renewable energy investment experience			
	Less than 5 years	31%	42%
	5 to 10 years	27%	19%
	10 to 15 years	27%	6%
	15 to 20 years	4%	0%
	20 to 25 years	8%	3%
	More than 25 years	0%	0%
	No investment experience	4%	29%
Company size			
	1-9	8%	32%
	10-99	27%	39%
	100-499	35%	10%
	More than 500	31%	19%